PX 313

From: "Walker, Tom" <twalker@riverstonellc.com>
Sent: Thu, 1 Feb 2018 14:01:15 +0000 (UTC)
To: "Hutchison, Susan" <SHutchison@riverstonellc.com>; "Coats, Stephen"<scoats@riverstonellc.com>
Cc: "Hackett, Jim" <JHackett@riverstonellc.com>
Subject: RE: SRII Proxy

Please forward to each director. The broadrige form can be sent my way.

Thanks.

From: Hutchison, Susan
Sent: Tuesday, January 30, 2018 5:29 PM
To: Coats, Stephen <scoats@riverstonellc.com>; Walker, Tom <twalker@riverstonellc.com>
Cc: Hackett, Jim <JHackett@riverstonellc.com>
Subject: SRII Proxy

We received individual copies of the SRII Proxy addressed to Diana W, Bill G, and Jeff T. Do these need to be forwarded to them?

The attached form from Broadridge was also received. Do you need the originals sent to NY?

Thanks,
Susan

PX 314

From: David McClure <dmcclure@AltaMesa.net>
Sent: Mon, 5 Feb 2018 15:21:48 +0000 (UTC)
To: "Hal H. Chappelle" <hchappelle@AltaMesa.net>
Cc: "Wang, Kevin" <KWang@riverstonellc.com>; "dkarian@riverstonellc.com"<dkarian@riverstonellc.com>; Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: RE: KFM 2018 detailed budget

Kevin / Drew - could you send me what you have regarding the 2018 / 2019 CAPEX budgets? I am attempting to dive into the numbers but need more detail than the table used in the road show / investor presentations.

I am attempting to create a more detailed budget to provide the BOD.

Thanks,

David McClure
Alta Mesa Services, LP
Vice President – Facilities & Midstream

281.943.5589 – office
dmcclure@altamesa.net

-----Original Message-----
From: Hal H. Chappelle
Sent: Sunday, February 04, 2018 1:00 PM
To: David McClure <dmcclure@AltaMesa.net>
Cc: Wang, Kevin <KWang@riverstonellc.com>; dkarian@riverstonellc.com; Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: KFM 2018 detailed budget

David - as we prepare materials for the initial AMR BOD meeting, you are providing input for infrastructure and midstream. Further, we are trying to conform as much as possible/practical our 2018 budget to the forecasts previously illustrated for investors. AEM (Mike C and Taylor) has indicated to you that Riverstone would be the best source of that information. So, per your request, I'm copying Kevin and Drew of Riverstone so that you can discuss the 2018 KFM assumptions they used in their contribution to the forecasts we included in the Investor Presentation. Also, copying Tamara.

Hal

Sent from my iPhone

PX 315

From:	Kevin J. Bourque <kbourque@AltaMesa.net> on behalf of Kevin J. Bourque <kbourque@AltaMesa.net>
Sent:	Friday, February 9, 2018 12:01 AM
To:	Kaitlyn Mathews <KMathews@AltaMesa.net>
Subject:	RE: Fwd: BOEPD Average

Use her numbers.

-----Original Message-----
From: Kaitlyn Mathews [KMathews@AltaMesa.net]
Received: Thursday, 08 Feb 2018, 5:57PM
To: Kevin J. Bourque [kbourque@AltaMesa.net]
Subject: RE: Fwd: BOEPD Average

Tamara uses 64.74% for all wells and 20% for BCE. Are we trying to get our WI or NRI volume?

From: Kevin J. Bourque
Sent: Thursday, February 08, 2018 5:53 PM
To: Kaitlyn Mathews <KMathews@AltaMesa.net>
Subject: RE: Fwd: BOEPD Average

Let's just run it as is and then ratio the gross numbers down to 78% in excel afterwards. Is that easier?

-----Original Message-----
From: Kaitlyn Mathews [KMathews@AltaMesa.net]
Received: Thursday, 08 Feb 2018, 5:47PM
To: Kevin J. Bourque [kbourque@AltaMesa.net]
Subject: RE: Fwd: BOEPD Average

I will sync again. I can change WI. Is that for all wells planned to drill this year 78%? Is that 64.7% NRI?

From: Kevin J. Bourque
Sent: Thursday, February 08, 2018 5:30 PM
To: Kaitlyn Mathews <KMathews@AltaMesa.net>
Subject: RE: Fwd: BOEPD Average

Tim just adjusted the PDP forecast, make sure your sync Aries again.

Can you adjust all wells up to an average of 78% WI?

Exhibit
CP - 0141
3/3/2023
Bourque

-----Original Message-----
From: Kaitlyn Mathews [KMathews@AltaMesa.net]
Received: Thursday, 08 Feb 2018, 4:38PM
To: Kevin J. Bourque [kbourque@AltaMesa.net]; Cathy Radvansky [cradvansky@AltaMesa.net]
Subject: Re: Fwd: BOEPD Average

Yes. I am just unclear on what scenario. I was thinking the 13 rig, 1mile radius SI for OEA/ Hinkle.

Sent via the Samsung Galaxy Note8, an AT&T 4G LTE smartphone

-------- Original message --------
From: "Kevin J. Bourque" <kbourque@AltaMesa.net>
Date: 2/8/18 4:29 PM (GMT-06:00)
To: Cathy Radvansky <cradvansky@AltaMesa.net>, Kaitlyn Mathews <KMathews@AltaMesa.net>
Subject: RE: Fwd: BOEPD Average

I think he's done now. Any chance you can run it from home?

-----Original Message-----
From: Kaitlyn Mathews [KMathews@AltaMesa.net]
Received: Thursday, 08 Feb 2018, 3:43PM
To: Kevin J. Bourque [kbourque@AltaMesa.net]; Cathy Radvansky [cradvansky@AltaMesa.net]
Subject: Fwd: BOEPD Average

FYI. Tim is wanting to update all the forecast. Once that is complete I will link it to Enersight and generate the latest production volumes. Hopefully this slide will be done by morning.

-------- Original message --------
From: Tim Turner <tturner@AltaMesa.net>
Date: 2/8/18 2:29 PM (GMT-06:00)
To: Kaitlyn Mathews <KMathews@AltaMesa.net>
Cc: Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: Re: BOEPD Average

Yes, updating now.

Tim

On Feb 8, 2018, at 2:27 PM, Kaitlyn Mathews <KMathews@AltaMesa.net> wrote:

> FYI I did the no SI and unlimited frac crews to show the extreme is would take to get to the 38MBOEPD average KB wanted me to achieve. I know it is not realistic.
>
> Tim, do you want me to wait until you have the PDP forecast updated? I also need to know what scenario to run with. I am thinking the OEA/ Hinkle with 1 mile SI radius.
>
> **From:** Tim Turner
> **Sent:** Thursday, February 08, 2018 2:18 PM
> **To:** Tamara Alsarraf <talsarraf@AltaMesa.net>
> **Cc:** Kaitlyn Mathews <KMathews@AltaMesa.net>
> **Subject:** RE: BOEPD Average
>
> Including Kaitlyn.
>
> **From:** Tamara Alsarraf
> **Sent:** Thursday, February 08, 2018 2:17 PM
> **To:** Tim Turner <tturner@AltaMesa.net>
> **Subject:** RE: BOEPD Average

Ok sounds good – thanks!

From: Tim Turner
Sent: Thursday, February 08, 2018 2:17 PM
To: Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: RE: BOEPD Average

Just talked to Hal. Leave type curve the same. I'm going to reforecast PDP, to take into account better operations.

From: Tamara Alsarraf
Sent: Thursday, February 08, 2018 2:12 PM
To: Tim Turner <tturner@AltaMesa.net>
Subject: RE: BOEPD Average

Also – Do you think I should just the type curve for new development wells? I am still using the type curve we had for the transaction.

<image001.png>

From: Tamara Alsarraf
Sent: Thursday, February 08, 2018 2:01 PM
To: Tim Turner <tturner@AltaMesa.net>
Subject: RE: BOEPD Average

Ok! Bigger impact than I thought, but glad it makes sense. I am not sure how to get back up to 38 – my model already has 5 frac crews in the 4th quarter!

From: Tim Turner
Sent: Thursday, February 08, 2018 1:50 PM
To: Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: RE: BOEPD Average

Makes sense that it is down because pattern average IP is quite a bit lower than type well. That impacts production all year. However, it's also possible the declines could be lower to total production is a little better, but probably not materially different.

From: Tamara Alsarraf
Sent: Thursday, February 08, 2018 1:46 PM
To: Tim Turner <tturner@AltaMesa.net>
Subject: RE: BOEPD Average

Not sure if that scenario makes sense if SI are off. Btw – we uploaded PDP into the model, and our average net boepd fell by quite a bit (from 38 to 33). I'm still looking into that, but does it make sense to you?

From: Kaitlyn Mathews
Sent: Thursday, February 08, 2018 1:44 PM
To: Kevin J. Bourque <kbourque@AltaMesa.net>
Cc: Cathy Radvansky <cradvansky@AltaMesa.net>; Tamara Alsarraf <talsarraf@AltaMesa.net>; Tim Turner <tturner@AltaMesa.net>

Subject: BOEPD Average

Kevin,

I ran several scenarios to show the production changes. I got to 38MBOEPD average when I turned off SI and included everything (not just OEA/ Hinkle). The average NRI for OEA/ Hinkle wells coming on in 2018 is 52.3% (with BCE) and 60.8% (without BCE). The STACK model is using an average of 64.74% for reference.

Enersight Rig Ramp: I added a 13th rig in June to just drill BCE. Below is the breakdown for Rig Count/ Frac crews. This scenario gets you 227 wells TD, 232 wells frac'd, and 217 wells on production.

<image002.png>

Scenario Results: BOEPD

<image003.png>

Please review and we can discuss.

PX 316

From: Tim Turner [tturner@AltaMesa.net]
on behalf of Tim Turner <tturner@AltaMesa.net> [tturner@AltaMesa.net]
Sent: 2/8/2018 3:53:14 PM
To: Kaitlyn Mathews [KMathews@AltaMesa.net]; Tamara Alsarraf [talsarraf@AltaMesa.net]
Subject: RE: BOEPD Average

Just finished forecasting ALL operated Hz wells. I'll run the PDP forecast shortly and send.

From: Kaitlyn Mathews
Sent: Thursday, February 08, 2018 2:28 PM
To: Tim Turner <tturner@AltaMesa.net>; Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: RE: BOEPD Average

FYI I did the no SI and unlimited frac crews to show the extreme is would take to get to the 38MBOEPD average KB wanted me to achieve. I know it is not realistic.

Tim, do you want me to wait until you have the PDP forecast updated? I also need to know what scenario to run with. I am thinking the OEA/ Hinkle with 1 mile SI radius.

From: Tim Turner
Sent: Thursday, February 08, 2018 2:18 PM
To: Tamara Alsarraf <talsarraf@AltaMesa.net>
Cc: Kaitlyn Mathews <KMathews@AltaMesa.net>
Subject: RE: BOEPD Average

Including Kaitlyn.

From: Tamara Alsarraf
Sent: Thursday, February 08, 2018 2:17 PM
To: Tim Turner <tturner@AltaMesa.net>
Subject: RE: BOEPD Average

Exhibit
CP- 0200
3/23/2023
Turner

Ok sounds good – thanks!

From: Tim Turner
Sent: Thursday, February 08, 2018 2:17 PM
To: Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: RE: BOEPD Average

Just talked to Hal. Leave type curve the same. I'm going to reforecast PDP, to take into account better operations.

From: Tamara Alsarraf
Sent: Thursday, February 08, 2018 2:12 PM
To: Tim Turner <tturner@AltaMesa.net>
Subject: RE: BOEPD Average

Also – Do you think I should just the type curve for new development wells? I am still using the type curve we had for the transaction.

PROPNUM	FirstOfSCENARIO	AREA	FIELD	LEASE	RESERVOIR	RSV_CAT	WI	NRI_OIL	OUTDATE	Gr_Oil	Gr_Gas	Residue	NGL	2ph MBOE	3ph MBOE	Year
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Apr-17	7,920	16,333	13,778	1,235	9,750	10,551	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-May-17	9,286	18,976	15,959	1,431	12,449	13,377	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Jun-17	9,488	21,979	18,485	1,657	13,146	14,221	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Jul-17	7,762	25,459	21,411	1,920	12,005	13,250	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Aug-17	6,607	26,498	22,285	1,998	11,023	12,319	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Sep-17	5,774	24,916	20,955	1,879	9,926	11,145	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Oct-17	5,142	23,552	19,807	1,776	9,067	10,218	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Nov-17	4,644	22,369	18,884	1,686	8,371	9,464	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Dec-17	4,342	21,308	17,920	1,607	7,793	8,835	2017
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Jan-18	3,909	20,372	17,133	1,536	7,304	8,300	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	28-Feb-18	3,628	19,532	16,426	1,473	6,884	7,839	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Mar-18	3,389	18,774	15,789	1,416	6,518	7,456	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Apr-18	3,181	18,085	15,210	1,364	6,196	7,090	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-May-18	3,000	17,457	14,681	1,316	5,910	6,763	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Jun-18	2,840	16,880	14,196	1,278	5,653	6,479	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Jul-18	2,698	16,348	13,749	1,233	5,423	6,222	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Aug-18	2,570	15,857	13,336	1,196	5,215	5,988	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Sep-18	2,455	15,401	12,952	1,161	5,022	5,775	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Oct-18	2,351	14,976	12,595	1,129	4,847	5,579	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Nov-18	2,256	14,580	12,262	1,099	4,686	5,399	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Dec-18	2,169	14,209	11,949	1,071	4,537	5,232	2018
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Jan-19	2,089	13,860	11,656	1,045	4,399	5,077	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	28-Feb-19	2,016	13,532	11,381	1,020	4,271	4,933	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Mar-19	1,947	13,223	11,121	997	4,151	4,798	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Apr-19	1,884	12,931	10,875	975	4,039	4,671	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-May-19	1,825	12,654	10,642	954	3,934	4,553	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Jun-19	1,770	12,392	10,422	934	3,835	4,441	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Jul-19	1,718	12,143	10,212	916	3,742	4,336	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Aug-19	1,670	11,906	10,013	898	3,655	4,237	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Sep-19	1,625	11,681	9,824	881	3,571	4,143	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Oct-19	1,582	11,466	9,643	865	3,493	4,053	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Nov-19	1,541	11,260	9,470	849	3,418	3,969	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Dec-19	1,503	11,063	9,304	834	3,347	3,888	2019
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Jan-20	1,467	10,875	9,146	820	3,280	3,811	2020
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	29-Feb-20	1,433	10,695	8,994	806	3,215	3,738	2020
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-Mar-20	1,400	10,522	8,849	793	3,154	3,668	2020
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	30-Apr-20	1,369	10,355	8,709	781	3,095	3,601	2020
58J292/S1Y	WORKING	Oklahoma	NE Kingfisher	7 Osage Gen 2.0 Type Well	MISS		100	83	31-May-20	1,340	10,195	8,574	769	3,039	3,537	2020

From: Tamara Alsarraf
Sent: Thursday, February 08, 2018 2:01 PM
To: Tim Turner <tturner@AltaMesa.net>
Subject: RE: BOEPD Average

Ok! Bigger impact than I thought, but glad it makes sense. I am not sure how to get back up to 38 – my model already has 5 frac crews in the 4th quarter!

From: Tim Turner
Sent: Thursday, February 08, 2018 1:50 PM
To: Tamara Alsarraf <talsarraf@AltaMesa.net>
Subject: RE: BOEPD Average

Makes sense that it is down because pattern average IP is quite a bit lower than type well. That impacts production all year. However, it's also possible the declines could be lower to total production is a little better, but probably not materially different.

From: Tamara Alsarraf
Sent: Thursday, February 08, 2018 1:46 PM
To: Tim Turner <tturner@AltaMesa.net>
Subject: RE: BOEPD Average

Not sure if that scenario makes sense if SI are off. Btw – we uploaded PDP into the model, and our average net boepd fell by quite a bit (from 38 to 33). I'm still looking into that, but does it make sense to you?

From: Kaitlyn Mathews
Sent: Thursday, February 08, 2018 1:44 PM
To: Kevin J. Bourque <kbourque@AltaMesa.net>
Cc: Cathy Radvansky <cradvansky@AltaMesa.net>; Tamara Alsarraf <talsarraf@AltaMesa.net>; Tim Turner

<tturner@AltaMesa.net>
Subject: BOEPD Average

Kevin,

I ran several scenarios to show the production changes. I got to 38MBOEPD average when I turned off SI and included everything (not just OEA/ Hinkle). The average NRI for OEA/ Hinkle wells coming on in 2018 is 52.3% (with BCE) and 60.8% (without BCE). The STACK model is using an average of 64.74% for reference.

Enersight Rig Ramp: I added a 13th rig in June to just drill BCE. Below is the breakdown for Rig Count/ Frac crews. This scenario gets you 227 wells TD, 232 wells frac'd, and 217 wells on production.

Date	Rig Count	BCE	Frac Crews
Jan-18	6		~3
Feb-18	6		4
Mar-18	6		4
Apr-18	8		4
May-18	8		4
Jun-18	10	1	4
Jul-18	10	1	4
Aug-18	12	1	4
Sep-18	12	1	4
Oct-18	12	1	5
Nov-18	12	1	5
Dec-18	12	1	5

Scenario Results: BOEPD

QTR	Average of 2 Mile SI (OEA/Hinkle)	Average of 2 Mile SI (ALL)	Average of 1 Miles SI (OEA/ Hinkle)	Average of 1 Miles SI (ALL)	Average of Unlimted Frac Crews - NO SI (OEA/Hinkle)	Average of Unlimted Frac Crews - NO SI (ALL)
- 2018						
Qtr1	23,493.48	25,614.26	24,103.59	26,263.01	24,661.49	25,839.24
Qtr2	26,727.39	28,828.13	27,707.70	29,839.07	29,408.66	31,563.37
Qtr3	33,062.99	37,655.84	34,099.43	38,707.25	35,632.05	40,281.61
Qtr4	39,271.70	46,579.87	42,149.04	49,681.47	45,630.00	53,088.56
BOEPD Average	30,688.75	34,760.23	32,070.12	36,173.78	33,895.43	38,021.47

Please review and we can discuss.

PX 317

From: "Walker, Tom" <twalker@riverstonellc.com>
Sent: Mon, 12 Feb 2018 13:59:20 +0000 (UTC)
To: "Zhu, Jingcai" <JZhu@riverstonellc.com>
Subject: FW: Riverstone Update – Silver Run Acquisition Corporation II Completes its Acquisition of Alta Mesa and Kingfisher Midstream
Attachments: SRII Completes Combination with Alta Mesa and KFM 02.09.2018.pdf

---

What are footnotes 1 and 2 in the text below? Did we just miss inclusion of the footnote?

From: Riverstone Limited Partner Relations
Sent: Friday, February 09, 2018 5:43 PM
To: Riverstone Limited Partner Relations
Subject: Riverstone Update – Silver Run Acquisition Corporation II Completes its Acquisition of Alta Mesa and Kingfisher Midstream

Dear Limited Partners of Riverstone Global Energy and Power Fund VI, L.P. ("Fund VI" or the "Fund"),

We wanted to share with you the attached press release announcing Silver Run Acquisition Corporation II's ("Silver Run II") completed acquisition of Alta Mesa Holdings, LP ("Alta Mesa") and Kingfisher Midstream, LLC ("Kingfisher"). Alta Mesa is an independent exploration and production company with assets located in the STACK play in Oklahoma. Kingfisher is engaged in the gathering, processing, and marketing of hydrocarbons in the STACK play.

The transaction was approved at a special meeting of Silver Run II's stockholders on February 6, 2018, with the approval of 98.43% of stockholders voting in person or by proxy. In connection with closing, Silver Run II has been renamed Alta Mesa Resources, Inc. ("Alta Mesa Resources"), and its common stock and warrants will be traded on NASDAQ under the symbols "AMR" and "AMRRW," respectively, beginning on February 12, 2018. Silver Run II invested approximately $1,042 million to consummate the transaction, and no redemption back-stop was required. As you may recall, Fund VI invested $200 million directly in Alta Mesa at the transaction signing in August 2017. At close, Fund VI funded an additional $400 million into Silver Run II through a forward purchase agreement entered into at Silver Run II's IPO in March 2017, bringing the total Fund VI investment to $600 million[1].

With approximately 130,000 contiguous net acres and an expansive inventory of 4,200 gross identified drilling locations, Alta Mesa is a leading pure-play exploration and production company focused on the STACK, one of the most prolific plays in North America. This transaction leaves Alta Mesa with a strong balance sheet that will enable continued rapid growth and development of its stacked-pay, low-breakeven, oil-weighted acreage. Furthermore, the combination with Kingfisher gives the pro forma company a highly synergistic and strategic midstream platform that complements Alta Mesa's development and possesses large third party growth potential. We are excited about possibilities for the combined company, including a potential future midstream IPO.

The company will continue to be led by CEO Hal Chappelle, who joined Alta Mesa as President and CEO in 2004 and has developed Alta Mesa into a premier STACK operator with a top-tier management and technical team. In addition, Jim Hackett will bring his management expertise and experience to his role as Executive Chairman of Alta Mesa Resources and COO of the midstream business. Jim Hackett joined Riverstone as a Partner, after having been the Chairman and CEO of Anadarko Petroleum, one of the largest U.S. independent E&P companies.

This deal is representative of a number of Riverstone's key competitive advantages. Riverstone's ability to source and execute a transaction of this size and scale was strengthened by our considerable experience with SPACs. Additionally, Riverstone leveraged our institutional sector expertise and proven success in operating E&P / midstream partnerships to underwrite the investment and develop a business plan for the company going forward, which we believe will generate significant synergies and compelling returns for investors. Based on the February 9th closing

share price, Fund VI's investment has an implied gross MOIC at transaction close of 1.3x[2].

If you have any questions please do not hesitate to contact us at Riverstone Limited Partner Relations (lprelations@riverstonellc.com).

Best regards,
Riverstone Limited Partner Relations

[1] Includes co-investment capital.

[2] Includes co-investment capital. Gross MOIC does not reflect management fees, carried interest, taxes, transaction costs and other expenses to be borne by investors in the fund, which will reduce returns and in the aggregate are expected to be substantial.

PX 318

From: "Wassenaar, Olivia" <owassenaar@riverstonellc.com>
Sent: Mon, 26 Feb 2018 00:44:42 +0000 (UTC)
To: Jim Hackett <jhackett@AltaMesa.net>
Cc: "Karian, Drew" <dkarian@riverstonellc.com>
Subject: Re: Planned Press Release

Thanks for sharing. Assume they are running this through counsel to make sure they don't have any issues — sure they are fine with the concept, but they may have some legal thoughts on the content.

Only thought I had was whether or not we could say something on specific recent well results or well level returns? Thinking about how we can counter some of the negative data from Marathon.

We actually did this a couple times with USAC when ArchRock had horrible results and they were bringing our share price down (despite good performance on our end). I think it is a good idea!

Again, thanks for sharing.

Olivia

On Feb 25, 2018, at 7:18 PM, Jim Hackett <jhackett@AltaMesa.net> wrote:

> Per our recent discussion, here is some "inside baseball" info at AMR. Hal wisely thinks we should get some operating information out to investors -- to combat the recent announcements calling the STACK into question – prior to our planned earnings call in late March.
> Jim
>
> Hal,
> This is excellent. Just before we release this, I would appreciate Mike M. or Lance W. sending it to the Board of Directors. This should be normal course for any PRs.
> I presume you considered and discarded speaking to gross volumes as well as net volumes. Also, I presume you considered and discarded trying to address the recent concerns expressed about the normally pressured oil window other than through the implied success we are having. I was just noodling about whether it is worth adding a quote saying that "our returns on capital at strip, given our existing production mix, financial discipline (in O&M and D&C costs) make the play very economic for our investors."
> Available to speak if needed.
> Good job on this.

From: Hal Chappelle <hchappelle@AltaMesa.net>
Date: Sunday, February 25, 2018 at 6:01 PM
To: Jim Hackett <jhackett@AltaMesa.net>
Cc: Mike McCabe <mmccabe@AltaMesa.net>, Tim Turner <tturner@AltaMesa.net>, Kevin Bourque <kbourque@AltaMesa.net>
Subject: Planned Press Release

Jim – as discussed last week, I suggest we would do well to provide investors with updated operations information while informing them of the schedule for our quarterly call. Please see the attached draft. Any / all comments are welcome, and would be happy to discuss in the morning.

Hal

<PR 02-26-18 Draft.docx>

PX 319

Alta Mesa Resources, Inc.

ALTA MESA RESOURCES ANNOUNCES YEAR-END 2017 PROVED RESERVES AND OPERATIONAL UPDATE

Houston, Texas, Feb. 27, 2018 – Alta Mesa Resources, Inc. (NASDAQ: AMR, AMRWW) ("Alta Mesa" or the "Company") today announced a summary of year-end 2017 proved reserves and provided an operational update, including associated production and drilling activity.

Year-End 2017 Reserves

Alta Mesa's oil, natural gas and natural gas liquids reserves as of December 31, 2017, were 176.2 million barrels of oil equivalent ("MMBOE") net to the Company, an increase of 46.6 MMBOE compared to 129.6 MMBOE at year-end 2016. Ryder Scott Company, LP, an independent reserve engineering firm, audited Alta Mesa's year-end proved reserves estimates as of December 31, 2017. Proved reserves consisted of 71.9 million barrels of oil, 36.1 million barrels of natural gas liquids, and 409 billion cubic feet of natural gas. Approximately 52 MMBOE of proved reserves at year-end 2017 were classified as proved developed producing (PDP) reserves, and approximately 124 MMBOE were classified as proved undeveloped (PUD) reserves. Through year-end 2017, the Company's reserves have grown in volume at a five-year compound annual growth rate of over 80%.

Operational Update

Full-year 2017 production net to the Company was approximately 21,000 BOE per day, a greater than 50% increase over 2016 net production of approximately 13,000 BOE per day. Total production mix for full-year 2017 was 52% oil, 17% natural gas liquids and 31% natural gas. Fourth quarter 2017 production was approximately 22,000 BOE per day, a greater than 45% increase over approximately 15,000 BOE per day in the fourth quarter 2016. Total production mix for the fourth quarter 2017 was 55% oil, 18% natural gas liquids and 27% natural gas. Through year-end 2017, the Company's net production has grown at a five-year compound annual growth rate of over 80%.

Alta Mesa deployed from four to six drilling rigs during 2017, drilled 108 gross wells (approximately 60 net wells), and completed 101 gross wells (approximately 56 net). The Company has had six drilling rigs and four fracture stimulation crews operating in early 2018, and has contracted for two additional drilling rigs to begin operating in March and April of 2018.

"The drilling and completion activity Alta Mesa has executed in the black oil window of the STACK during 2017, coupled with leasehold acquisitions, has set the stage for a deliberate program of multi-well pattern development," stated Alta Mesa's Chief Executive Officer, Hal Chappelle. "Our capital and operating cost structure and production mix have continued to foster economic returns on capital for our investors. With the planned increased level of activity in our 2018 program, we expect to capitalize upon the efficiency gains and execution success we had last year, resulting in what we believe will be continued long-term corporate-level returns and value creation."

Fourth Quarter and Full Year 2017 Earnings Conference Call

Alta Mesa will report fourth quarter and full year 2017 financial results, and provide an operational update and 2018 guidance on Thursday, March 29th, 2018. The Company invites you to listen to its conference call to discuss these results on that date at 11:00 a.m. Eastern Time. If you wish to participate in this conference call, dial 888-347-8149 (toll free in US/Canada) or 412-902-4228. A webcast of the call and any related materials will be available on the Company's website at www.altamesa.net. Additionally, a replay of the conference call will be available for one week following the live broadcast by dialing 844-512-2921 (toll free in US/Canada) or 412-317-6671 (International calls), and referencing Conference ID # 10117607.

About Alta Mesa Resources, Inc.

Alta Mesa Resources, Inc. is an independent energy company focused on the development and acquisition of unconventional oil and natural gas reserves in the Anadarko Basin in Oklahoma and provides midstream energy services, including crude oil and gas gathering, processing and marketing to producers in the STACK play region through Kingfisher Midstream, LLC.

Safe Harbor Statement and Disclaimer

Alta Mesa has prepared the summary preliminary data in this release based on the most current information available to management. Alta Mesa's normal financial reporting processes with respect to the preliminary data herein have not been fully completed and, as a result, its actual results could be different from this summary preliminary information presented herein, and any such differences could be material. The information in this press release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of present or historical fact included in this press release, regarding Alta Mesa's strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this press release, the words "could", "should", "will", "may", "believe", "anticipate", "intend", "estimate", "expect", "project," the negative of such terms and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on Alta Mesa's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. Alta Mesa cautions you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond its control, incident to the exploration for and development and production, gathering and sale of oil, natural gas, and natural gas liquids. These risks include, but are not limited to: commodity price volatility, low prices for oil, natural gas and/or natural gas liquids, global economic conditions, inflation, increased operating costs, lack of availability of drilling and production equipment supplies, services and qualified personnel, processing volumes and pipeline throughput, uncertainties related to new technologies, geographical concentration of operations of our subsidiaries Alta Mesa Holdings, LP ("Alta Mesa Holdings") and Kingfisher Midstream, LLC ("KFM"), environmental risks, weather risks, security risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and natural gas reserves and in projecting future rates of production, reductions in cash flow, lack of access to capital, Alta Mesa Holdings and KFM's ability to satisfy future cash obligations, restrictions in existing or future debt agreements of Alta Mesa holdings or KFM, the timing of development expenditures, managing Alta Mesa Holdings and KFM's growth and integration of acquisitions, failure to realize expected value creation from property acquisitions, title defects and limited control over non-operated properties, the Company's ability to complete an initial public offering of the KFM midstream business and the other risks described in the Company's filings with the SEC. Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. Specifically, future prices received for production and

costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. Sustained lower prices will cause the twelve-month weighted average price to decrease over time as the lower prices are reflected in the average price, which may result in the estimated quantities and present values of Alta Mesa's reserves being reduced. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered. Should one or more of the risks or uncertainties described in this press release occur, or should underlying assumptions prove incorrect, Alta Mesa's actual results and plans could differ materially from those expressed in any forward-looking statements. All forward-looking statements, expressed or implied, included in this press release are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that Alta Mesa may issue. Except as otherwise required by applicable law, Alta Mesa disclaims any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this press release.

FOR MORE INFORMATION CONTACT: Lance L. Weaver (281) 943-5597 lweaver@altamesa.net

PX 320

Alta Mesa Resources, Inc.

Reserves Discussion and Contrast of Production Data and Public Sales Data

March 2018

Exhibit
CP 0470
Gutermuth

Disclaimer

FORWARD-LOOKING STATEMENTS

The information in this presentation and the oral statements made in connection therewith include "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of present or historical fact included in this presentation, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this presentation, including any oral statements made in connection therewith, the words "could," "should," "will," "may," "believe," "anticipate," "intend," "estimate," "expect," "project," the negative of such terms and other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on management's current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the development, production, gathering and sale of oil, natural gas and natural gas liquids. These risks include, but are not limited to, commodity price volatility, low prices for oil and/or natural gas, global economic conditions, inflation, increased operating costs, lack of availability of drilling and production equipment, supplies, services and qualified personnel, processing volumes and pipeline throughput, uncertainties related to new technologies, geographical concentration of operations of our subsidiaries Alta Mesa Holdings, LP ("Alta Mesa") and Kingfisher Midstream, LLC ("KFM"), environmental risks, weather risks, security risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and natural gas reserves and in projecting future rates of production, reductions in cash flow, lack of access to capital, Alta Mesa's and KFM's ability to satisfy future cash obligations, restrictions in existing or future debt agreements of Alta Mesa or KFM, the timing of development expenditures, managing Alta Mesa's and KFM's growth and integration of acquisitions, failure to realize expected value creation from property acquisitions, title defects and limited control over non-operated properties, our ability to complete an initial public offering of the KFM midstream business and the other risks described in our filings with the Securities and Exchange Commission (the "SEC"). Should one or more of the risks or uncertainties described in this presentation and the oral statements made in connection therewith occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this presentation.

RESERVE INFORMATION

Reserve engineering is a process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could impact our strategy and change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered. Estimated Ultimate Recoveries, or "EURs," refers to estimates of the sum of total gross remaining proved reserves per well as of a given date and cumulative production prior to such given date for developed wells. These quantities do not necessarily constitute or represent reserves as defined by the SEC and are not intended to be representative of anticipated future well results of all wells drilled on our STACK acreage.

USE OF PROJECTIONS

This presentation contains projections for Alta Mesa and KFM, including with respect to their EBITDA, net debt to EBITDA ratio and capital budget, as well as Alta Mesa's production and KFM's volumes, for the fiscal years 2017, 2018 and 2019. Neither our, nor Alta Mesa's and KFM's independent auditors or Alta Mesa's independent petroleum engineering firm have audited, reviewed, compiled, or performed any procedures with respect to the projections for the purpose of their inclusion in this presentation, and accordingly, none of them expressed an opinion or provided any other form of assurance with respect thereto for the purpose of this presentation. These projections are for illustrative purposes only and should not be relied upon as being necessarily indicative of future results. In this presentation, certain of the above-mentioned projected information has been repeated (in each case, with an indication that the information is subject to the qualifications presented herein), for purposes of providing comparisons with historical data. The assumptions and estimates underlying the projected information are inherently uncertain and are subject to a wide variety of significant business, economic and competitive risks and uncertainties that could cause actual results to differ materially from those contained in the projected information. Even if our assumptions and estimates are correct, projections are inherently uncertain due to a number of factors outside our control. Accordingly, there can be no assurance that the projected results are indicative of our future performance or that actual results will not differ materially from those presented in the projected information. Inclusion of the projected information in this presentation should not be regarded as a representation by any person that the results contained in the projected information will be achieved.

USE OF NON-GAAP FINANCIAL MEASURES

This presentation includes non-GAAP financial measures, including EBITDA and Adjusted EBITDAX. Please refer to the Appendix for a reconciliation of Adjusted EBITDAX to net (loss) income, the most comparable GAAP measure. We believe EBITDA and Adjusted EBITDAX are useful because they allow us to more effectively evaluate our operating performance and compare the results of our operations from period to period and against their peers without regard to financing methods of capital structure. The computations of EBITDA and Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. We exclude the items listed in the Appendix from net (loss) income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that its results will be unaffected by unusual or non-recurring items.

INDUSTRY AND MARKET DATA

This presentation has been prepared by us and includes market data and other statistical information from sources we believe to be reliable, including independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates, which are derived from our review of internal sources as well as the independent sources described above. Although we believe these sources are reliable, we have not independently verified the information and cannot guarantee its accuracy and completeness.

TRADEMARKS AND TRADE NAMES

We own or have rights to various trademarks, service marks and trade names we use in connection with the operation of our business. This presentation also contains trademarks, service marks and trade names of third parties, which are the property of their respective owners. The use or display of third parties' trademarks, service marks, trade names or products in this presentation is not intended to, and does not imply, a relationship with us, or an endorsement or sponsorship by or of us. Solely for convenience, the trademarks, service marks and trade names referred to in this presentation may appear without the ®, TM or SM symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the right of the applicable licensor to these trademarks, service marks and trade names.

Production Data and Public Sales Data

Purpose and scope of analysis

- **Purpose**
  - Provide recently-audited EUR data by well
  - Summarize assessment of public data compared to actual production
  - Evaluate 2017 actual average well performance
  - Provide context for reliability of monthly public data

- **Scope of Analysis**
  - EUR data
    - Share audited YE 2017 EUR results
    - Identify wells excepted from reserve distribution and describe exceptions
  - Public data
    - Use wells in distribution to view public production data relative to type curve
    - Well-by-well, month-by-month comparison of Alta Mesa wellhead oil and gas production with Oklahoma public sales data
    - Timing: January 2016 through October 2017
    - Public data is latest available (October 2017) from DrillingInfo

Production Data and Public Sales Data

Oil data consistent – Gas data significantly different

Key Point: Unlike states where the producer reports wellhead production to the state regulator body (Texas – TRRC, Louisiana – DNR), in Oklahoma the purchaser reports sales to the Oklahoma Tax Commission

Findings

- **Production and sales data for oil compare very closely**
  - Production data slightly higher than sales at any given time due to the lag time with tank sales
  - Public data accurately reflect purchaser reporting, few errors
  - Later month sale volumes are much lower than production mostly due to slow reporting of new wells
  - Most oil sold at wellhead tank/facility; some sold through LACT meters which are highly accurate

Data Range	Oil Prod Bbls	Public-Sales Bbls	Sales/Prod Ratio
Jan 16 - Dec 16	3,624,751	3,615,173	100%
Jan 16 - Mar 17	4,912,056	4,896,052	100%
Jan 16 - Jun 17	6,268,169	6,243,932	100%
Jan 16 - Sep 17	7,743,963	7,662,848	99%
Jan 16 - Oct 17	8,308,805	8,163,621	98%
Jan 17 - Mar 17	1,287,305	1,280,879	100%
Apr 17 - Jun 17	1,356,113	1,347,880	99%
Jul 17 - Sep 17	1,475,793	1,418,916	96%
Oct 17	564,842	500,773	89%

- **Gas production data and sales data vary**
  - Sales volumes may be reported from different sales points (plant inlet, CRP, wellhead); production volumes impacted by lease fuel, lift gas, line losses, flaring, etc.
  - At a well level, wellhead volumes may be impacted by allocation of volumes (provided to purchaser by producer) and allocated sales at the well are reported by the purchaser
  - Public sales volumes can lag several months

Date Range	Gas Prod MCF	Public-Sales MCF	Sales/Prod Ratio
Jan 16 - Dec 16	14,065,268	12,173,355	87%
Jan 16 - Mar 17	19,171,418	17,308,061	90%
Jan 16 - Jun 17	24,868,391	23,469,599	94%
Jan 16 - Sep 17	31,423,698	29,231,740	93%
Jan 16 - Oct 17	33,610,729	29,477,182	88%
Jan 17 - Mar 17	5,106,150	5,134,706	101%
Apr 17 - Jun 17	5,696,973	6,161,538	108%
Jul 17 - Sep 17	6,555,307	5,762,141	88%
Oct 17	2,187,031	245,442	11%

Year End Proved Reserves
Reconciliation with public production data

- YE 2017 proved reserves based on a distribution of 146 producing wells
- Oil EURs are broadly consistent north to south; with averages lagging in north (township 19N)
  - Northern area includes 4 wells in township 19N 5W, 19 wells in 19N 6W
  - 19N wells have shortest average lateral length at about 250' less than average
- Exceptions from distribution consider various factors (listed in Appendix); examples:
  - Generation 1.0 and 1.5 completions
  - Pattern tests at closer than 750' between laterals
  - Early-period wells with casing failure or fracture-stimulated at lower intensity due to casing concerns
  - Four isolated wells with high water (two in Section 19 of 19N6W optimized with artificial lift late 2017, not included in YE17 distribution)
  - Six wells pending artificial lift optimization

AREA	EUR, MBO	EUR, MMCF	LATERAL	# WELLS	
Average 15N	267	1,959	4,724	18	Southern Area
Average 16N	249	1,962	4,660	14	
Average 17N	260	2,174	4,779	69	Central Area
Average 18N	251	1,806	4,646	20	
Average 19N	224	757	4,438	23	Northern Area
Average 20N	370	1,057	4,771	2	
Average YE17 Distribution	**254**	**1,838**	**4,689**	**146**	

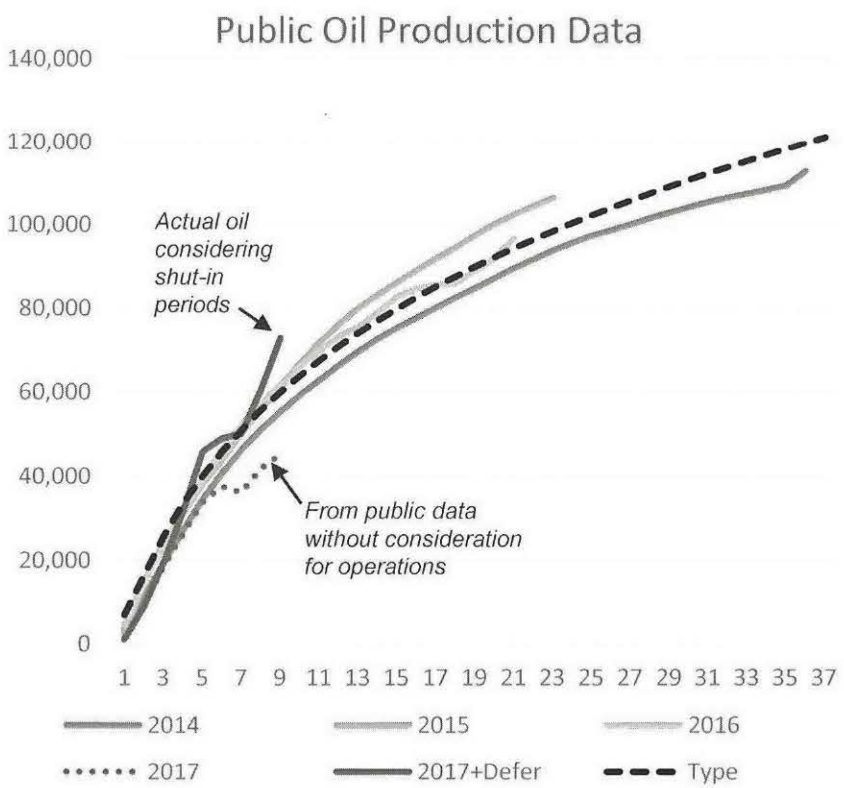
	MBO	MMCF	2-phase MBOE	3-Phase MBOE*	Well IRR	Corp IRR
Type Curve	250	1,868	561	651	61%	76%
Normalized to 10,000'	533	3,984	1,197	1,388		

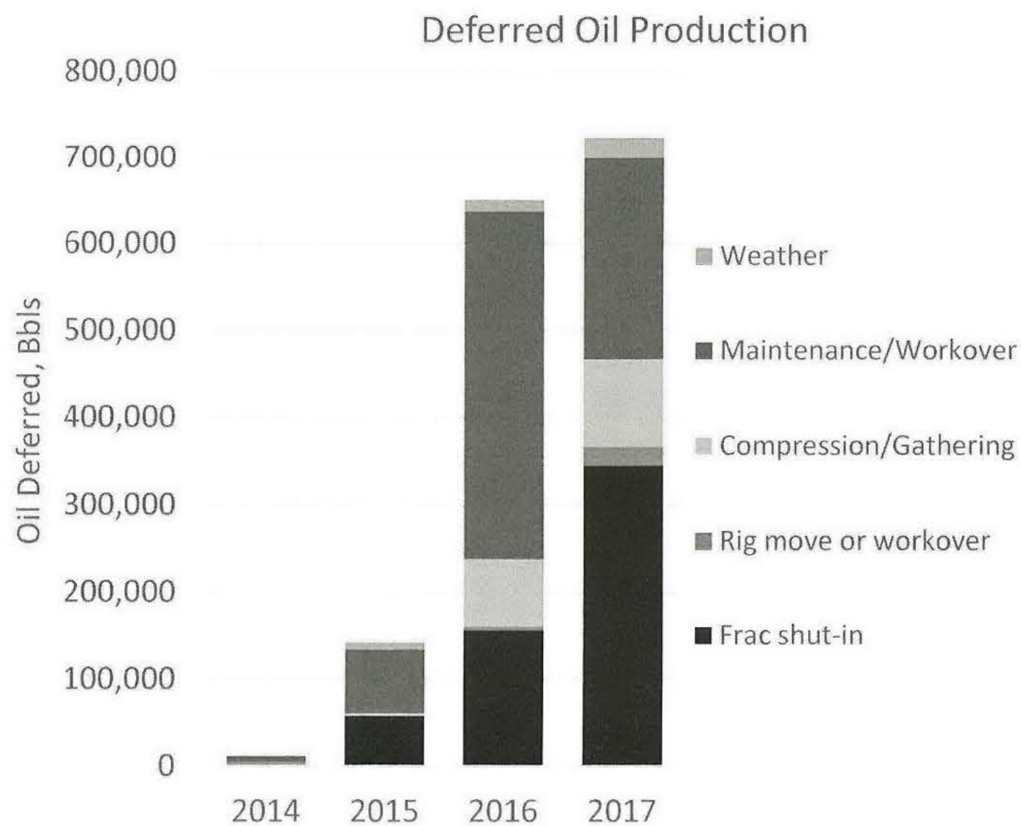
Technical EUR based on audited reserves, 3-phase with ethane rejection
* 3-Phase MBOE assumes KFM connection with 15% shrink and 73 bbls/mmcf NGL yield with ethane rejection

Alta Mesa Resources Production/Sales Analysis

2015-2017 trending above type curve

- Detailed well reserves provide confidence in reserve assessments
- Public oil sales data were derived from DrillingInfo for wells in Alta Mesa's distribution for further analysis of other factors
- Data illustrate 2014 and 2015 trend upward; 2016 and 2017 public data suggest other factors are at play
- Key Finding: operational factors such as shut-in and deferred production must be understood, as shown below
  - As wells come on production, more rigs are introduced and more patterns are drilled, or downtime factors emerge
  - Most downtime is related to compression, offset frac, short-term water hit from an offset frac, and wells awaiting repair or lift optimization
  - Of 84 wells that started producing oil in 2017, 55 were subjected to downtime, deferring approximately 185,000 bbls of oil
  - Accounting for deferred production results in "2017 + Defer" average rate shown below





Alta Mesa Resources STACK EUR Update

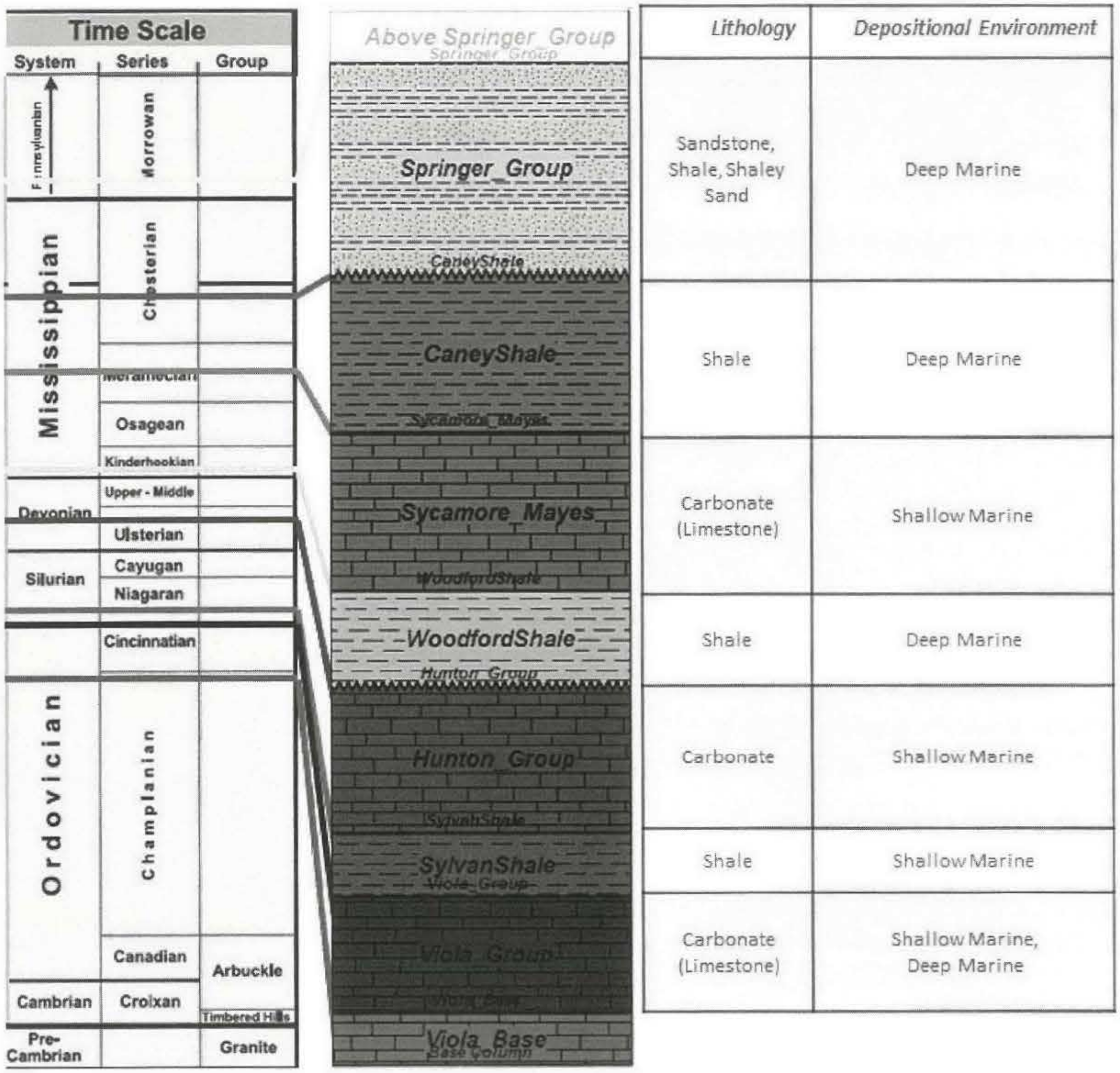
146 Wells Included (Township, Range, Section, Generation)

API	WELL	SEC	TWN	RNG	IP_DATE	IP_YEAR	AREA	TECH_EUR_MBO	TECH_EUR_MMCF	SEC_EUR_MBO	SEC_EUR_MMCF	LATERAL
3507325252	Cronkite 1505 4-14MH	14	15N	05W	10/8/2016	2016		202	957	165	644	4,808
3507325439	Shiner 1505 1-3MH	3	15N	05W	4/13/2017	2017		183	1,355	165	1,123	4,899
3507325417	Best Thirty 1505 1-5MH	5	15N	05W	3/6/2017	2017		109	464	82	387	4,865
3507325375	Redbreast 1505 4-7MH	7	15N	05W	12/15/2016	2016		269	1,990	250	1,715	4,709
3507325378	Yellowstone 1505 4-8MH	8	15N	05W	2/13/2017	2017		290	2,432	275	2,186	4,730
3507325318	Martin 1505 4-9MH	9	15N	05W	9/17/2016	2016		310	3,891	300	3,646	4,795
3507325272	Dixon 1505 3-16MH	16	15N	05W	10/20/2016	2016		309	2,722	295	2,465	4,858
3507325336	Three Wood 1505 4-17MH	17	15N	05W	12/6/2016	2016		291	2,540	275	2,257	4,634
3507325517	Aberlour 1505 1-18MH	18	15N	05W	10/15/2017	2017		181	1,908	168	1,654	4,772
3507325731	Samuel 1505 1-29MH	29	15N	05W	10/6/2017	2017		336	2,410	325	2,242	4,862
3507325461	Red Queen 1506 1-1MH	1	15N	06W	3/25/2017	2017		183	2,005	173	1,788	4,078
3507325440	White King 1506 1-12MH	12	15N	06W	3/28/2017	2017		305	2,136	293	1,962	4,804
3507325481	Cheshire Cat 1506 1-13MH	13	15N	06W	7/20/2017	2017		306	2,814	292	2,560	4,655
3507325431	Huntsman 1506 2-23MH	23	15N	06W	4/16/2017	2017		319	2,287	308	2,115	4,558
3507325457	Huntsman 1506 4-23MH	23	15N	06W	4/25/2017	2017		278	1,516	262	1,344	4,766
3507325611	Old Crab 1506 1-24MH	24	15N	06W	7/17/2017	2017		366	2,442	349	2,194	4,765
3507325370	White Rabbit 1506 2-27MH	27	15N	06W	11/30/2016	2016		313	722	275	580	4,811
3507325364	Mad Hatter 1506 2-34MH	34	15N	06W	12/9/2016	2016		263	665	225	523	4,670
							Average 15N	**267**	**1,959**	**249**	**1,743**	**4,724**
3507325181	Helen 1605 5-33MH	33	16N	05W	2/13/2016	2016		236	1,790	219	1,554	4,620
3507325296	Rudd 1605 2A-5MH	5	16N	05W	8/5/2016	2016		183	2,055	162	1,535	4,010
3507325735	McLovin 1605 1-6MH	6	16N	05W	10/15/2017	2017		150	1,343	134	1,106	4,182
3507325707	Jacob 1605 1-8MH	8	16N	05W	10/2/2017	2017		358	2,609	342	2,383	4,812
3507325482	Aberfeldy 1605 4-16MH	16	16N	05W	7/21/2017	2017		237	1,706	217	1,452	4,756
3507325508	Hasley 1605 1-28MH	28	16N	05W	6/11/2017	2017		323	2,186	304	1,944	4,742
3507325306	Oak Tree 1605 2-30MH	30	16N	05W	9/27/2016	2016		266	1,656	247	1,430	4,744
3507325493	Dalwhinnie 1605 1-31MH	31	16N	05W	5/14/2017	2017		249	1,911	231	1,651	4,812
3507325592	PlumpJack 1605 1-34MH	34	16N	05W	6/30/2017	2017		208	1,858	193	1,602	4,797
3507325572	Opus One 1605 1-35MH	35	16N	05W	7/28/2017	2017		157	1,192	136	944	4,569
3507325486	Aces High 1606 4-11MH	11	16N	06W	5/24/2017	2017		167	2,219	153	1,748	4,776
3507325441	Peat 1606 1-26MH	26	16N	06W	6/1/2017	2017		241	1,657	228	1,484	4,743
3507325523	Speyside 1606 1-27MH	27	16N	06W	6/3/2017	2017		334	2,533	322	2,344	4,851
3507325562	Sadiebug 1606 1-35MH	35	16N	06W	7/18/2017	2017		378	2,757	367	2,584	4,820
							Average 16N	**249**	**1,962**	**233**	**1,697**	**4,660**

SEC EUR YE17 Audited by Ryder Scott & Co (SEC prices $53.49/bbl, $3.00/mmbtu)
Technical EUR based on audited reserves

APPENDIX

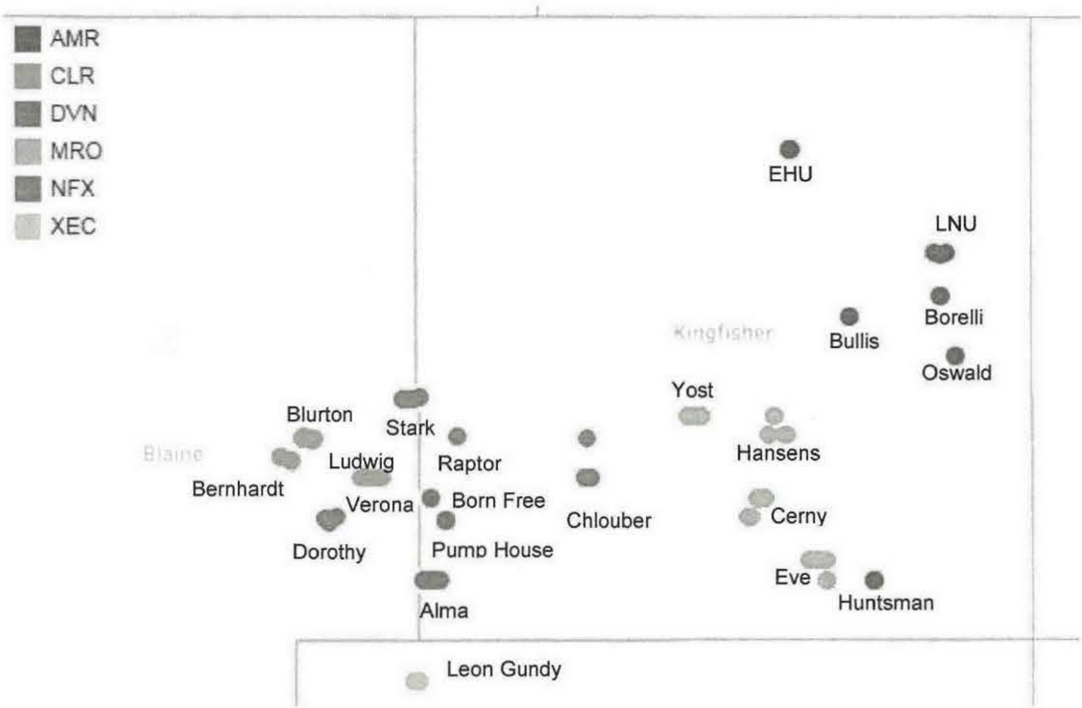
Anadarko Basin Stratigraphy



Source: DrillingInfo

Review of Key Density Pilots in the STACK Black Oil Window

STACK Density Test Pilots Map



Source: Company Presentation, DrillingInfo, Guggenheim Securities, LLC Research

As the most active operator in the STACK Black Oil Window, AMR has conducted some of the oldest spacing tests in the region and is shifting from delineation to development. The state data suggests more child wells are performing in-line or better than the parent wells. AMR has tested densities as low as 660' and has seen communication between wells. They have high conviction that the optimal density is 1,300'–1,400' inter-well spacing and three intervals per section. Our inventory estimate is based on 1,500' inter-well or 750' between staggered wells where two landing zones are present.

MRO

- *Yost*: MRO's first Meramec infill pilot in the normally pressured black oil window. The six wells had an average ip30 of 990 boe/d. Yost successfully tested 110 acre/well spacing with completions of ~2,500 lbs/ft, yet the wells reported weaker production than many of the surrounding offset wells. Lateral length and well interference during infill operations were cited as potential causes for the pilot's less-than optimal performance. The Yost pilot demonstrated wide variance in individual well results and significant degradation to the parent well despite aggressive stimulation. Competing operators have suggested the pattern of the pilot may be to blame, with the parent well drilled in the middle of pattern rather than at the edges But we believe the wells could have been economic, with the *average* of the wells tracking a 940 mmboe standard lateral type curve (57% oil). This should earn an unburdened IRR of 50% at $50 / $3.

- *Hansens*: a 7-well Meramec infill project testing two intervals in the Upper and Lower Meramec. MRO seems to have had more success with Hansens than Yost (in terms of well variability). The wells were spaced 1,320' apart per interval with the Upper and Lower Meramec separated 100' vertically. Two of the six infill wells under-performed but the other wells compensated for the under-performance.

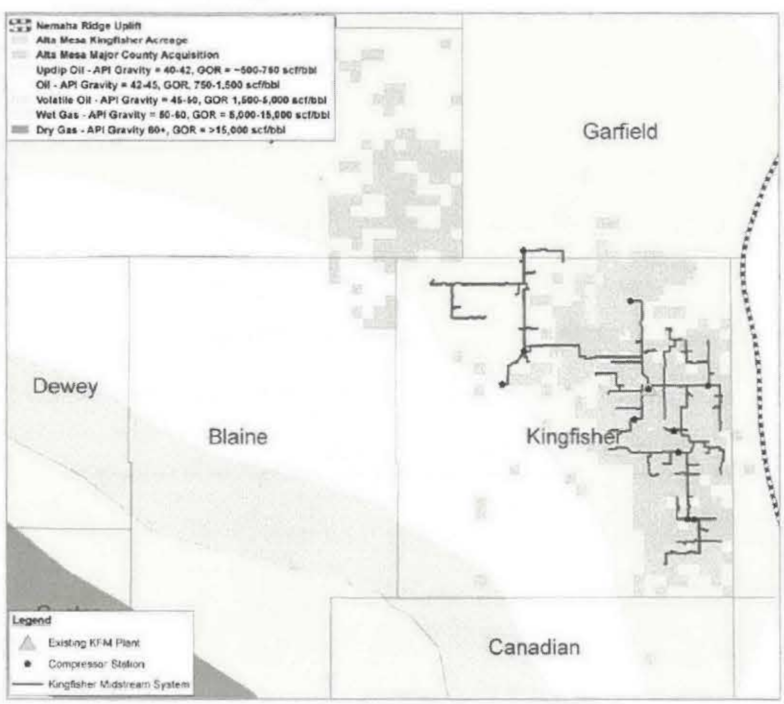
- *Eve*: a 6-well Meramec infill project testing two intervals in Upper and Lower Meramec with 1,320' spacing between wells in each interval. Two of the six infill wells under-performed but the other wells compensated. However, completion intensity was relatively low which allows room for improvement. In any case, optimal density appears to be 4 wells per interval.

- *Cerny*: MRO's most recent density test pilot, a 6-well infill project (in a half section) co-developing multiple horizons including the Upper and Lower Meramec, Osage and Woodford. Three of the 5 infill wells are targeting 2 intervals in the Meramec; the other 2 infill wells are targeting the Osage and Woodford formation respectively. Spacing in the Meramec formation in the Cerny is equivalent to 4 Meramec wells per section (1,320'), 2 Meramec landing zones per section. The pilot has achieved an average IP30 of 603 boepd (64% oil). MRO experienced communications between the Osage and the Woodford, but not between the Meramec and those intervals. More tests like this are necessary to understand communication across AMR's acreage as the play varies from north to south and east to west.

NFX

- *Chlouber*: NFX's first STACK infill pilot looked good in the Upper and Lower Meramec. It tested 1,050' spacing per interval (5 wells per interval) with long laterals. The infill wells were tested with higher intensity than the parent using the 2,100:2,100 proppant/fluid volume design. However the Meramec column was thicker in the Chlouber than the spacing tests mentioned above.

STACK Fluid Window Map



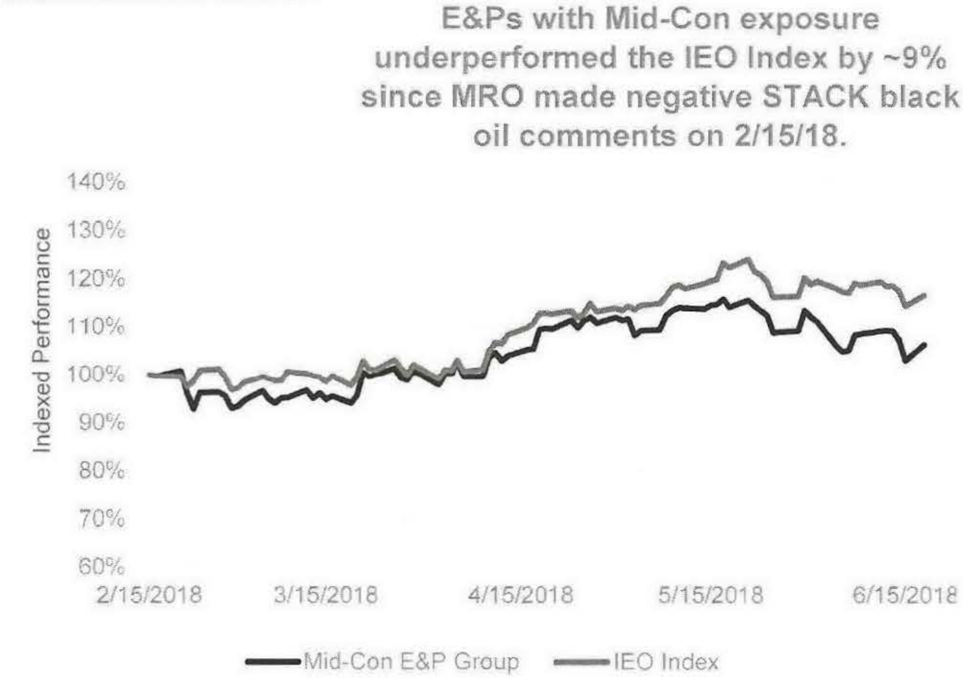
Source: Company Presentation

 See pages 43 - 44 for analyst certification and important disclosures.

Recent Stock Underperformance Can Turnaround Through Execution

On the 4Q17 call, MRO announced a mixed bag of well results in the STACK. MRO has drilled four pilots (Yost, Hansen, Eve, Cerny) in the STACK black oil window to test well spacing with 6 to 9 wells per section. The results were below MRO's expectations and MRO decided to moderate its pace in the normal-pressured black oil window. The Eve, a 7-well infill test, was MRO's eastern-most test. According to MRO, data from the Eve suggests that on the far east side of the STACK play, the optimal spacing will likely be less than six wells per section, but location count per DSU will increase moving west into the thicker and more geo-pressured areas. Also NFX delivered a disappointing fourth quarter primarily because oil guidance came in below consensus estimates. CLR revised STACK type curves down ~30% from previous estimates based on their updated economic model, which assumes 4 Meramec wells per interval or 8 Meramec wells per DSU given the multi-zone potential. DVN also indicated that the porosity and permeability of the Meramec supports well density less than its original expectations. These negative commentaries impacted STACK sentiment and caused Mid-Con names to lag E&P indices. Since MRO's 4Q17 call, Mid-Con operators as a group have underperformed IEO index by ~9% on average.

Indexed Stock Performance



Note: The Mid-Con company group includes AMR, CLR, DVN, GST, JCO, JONE, MRO, NFX, SD and XEC.

Source: FactSet, Guggenheim Securities, LLC Research

As noted in our Sep. 2017 "Density Warfare" report, data suggests significant parent-child communication in MRO's Yost pilot. The six-well Yost pilot demonstrated wide variance in individual well results and significant degradation to the parent well despite aggressive stimulation. The issue is more about optimal well spacing and well costs in the black oil window, rather than the prospectivity of the black oil window itself. As noted in our May 2017 "Thesis Hits and Misses" report, proper spacing is more in the 160-200 acres per interval (1,300' to 1,700') rather than 100 acres (800 – 1,000'). From our conversations with other Mid-Con operators, MRO's issues were cost-related as well, not entirely productivity related.

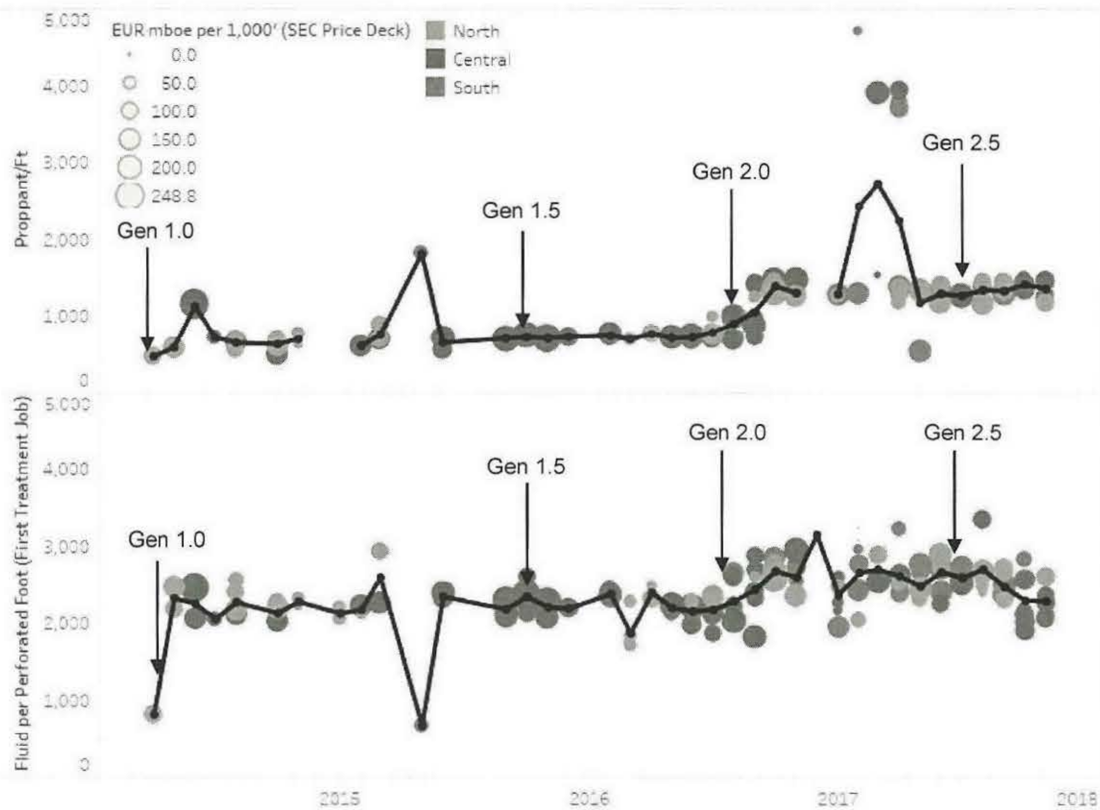
We believe sentiment towards the Mid-Con will improve. In the black oil window, the market has focused on geologic risk (drainage, pressures) and third-party commentary (MRO) rather than AMR's track record. As the company executes on the growth plan, showing high levels of sequential oil growth (we expect double-digit growth for two years), we expect sentiment to improve. AMR is uniquely positioned to benefit from the appetite for non-Permian oil (although Cushing risk remains) in an area with stacked potential and running room. Overlooked in the criticism of the black oil window are the lower well costs. AMR compensates for lower flow rates with substantially lower well costs than in other shale oil plays. It is critical that AMR maintains this cost advantage. In over-pressured areas, additional casing strings and expensive drilling mud designs are required to maintain control of the well. Adding casing strings means more cement jobs and rig time are needed. Normally-pressured oil windows are among the lowest cost region within the STACK, with, on average, depths of less than 10,000' and drill times of less than 20 days. Shallow targets allow operators to eliminate additional strings of casing and reduce horsepower used during stimulation. For example, AMR's Osage and Meramec wells require just two strings of casing instead of three or more in some parts of the STACK. In the deeper and gassier regions of the STACK, recent well costs have varied from $8-$12 million with vertical depths ranging from 13,000' - 16,000' and cycle times of 60 to 80 days. AMR's wells cost $4mm, or ~$800/ft, with a target of $3.5mm in pad development. The average spud-to-TD is two weeks and oil cuts are high at ~50%.

WELL RESULTS

Completion Optimization Is Driving Well Performance

Over the last several years, we have seen a rapid increase in completion intensity for both proppant and fluid loading in the STACK play. Well productivity has responded positively, with higher IP rates comparing to older vintage wells. AMR has modified its completion design over the years, with increased proppant intensity and fluid volume, along with tighter stage spacing, while keeping its lateral length constant at ~4,800 ft. or about one mile. AMR's proppant intensity has risen from less than 460 lbs./ft. in 2013/2014 to ~680 lbs./ft. in 2015/2016 to ~1,280 lbs./ft. in late 2016/2017. Proppant intensities for Osage wells tend to be less than in the Meramec because of the presence of natural fractures in the Osage formation. Proppant loading of AMR's latest Gen 2.5 completion design is optimum at an average of 1,400 lbs./ft., 32 stages (150' stage spacing), 6.1 million lbs. of proppant, and 300,000 bbls of fluid (63 bbls/ft.). AMR deploys a traditional slickwater fluid system design, while most STACK operators deploy a hybrid system. These are open-hole completions (no cemented liners) with swellable packers. Wells are put on gas-lift immediately, which ultimately transitions to ESP's, jet pumps or rod pumps. The vast majority of AMR's wells are on gas lift currently with upside from ESP's or other artificial lift methodologies.

AMR Completion Design Evolution

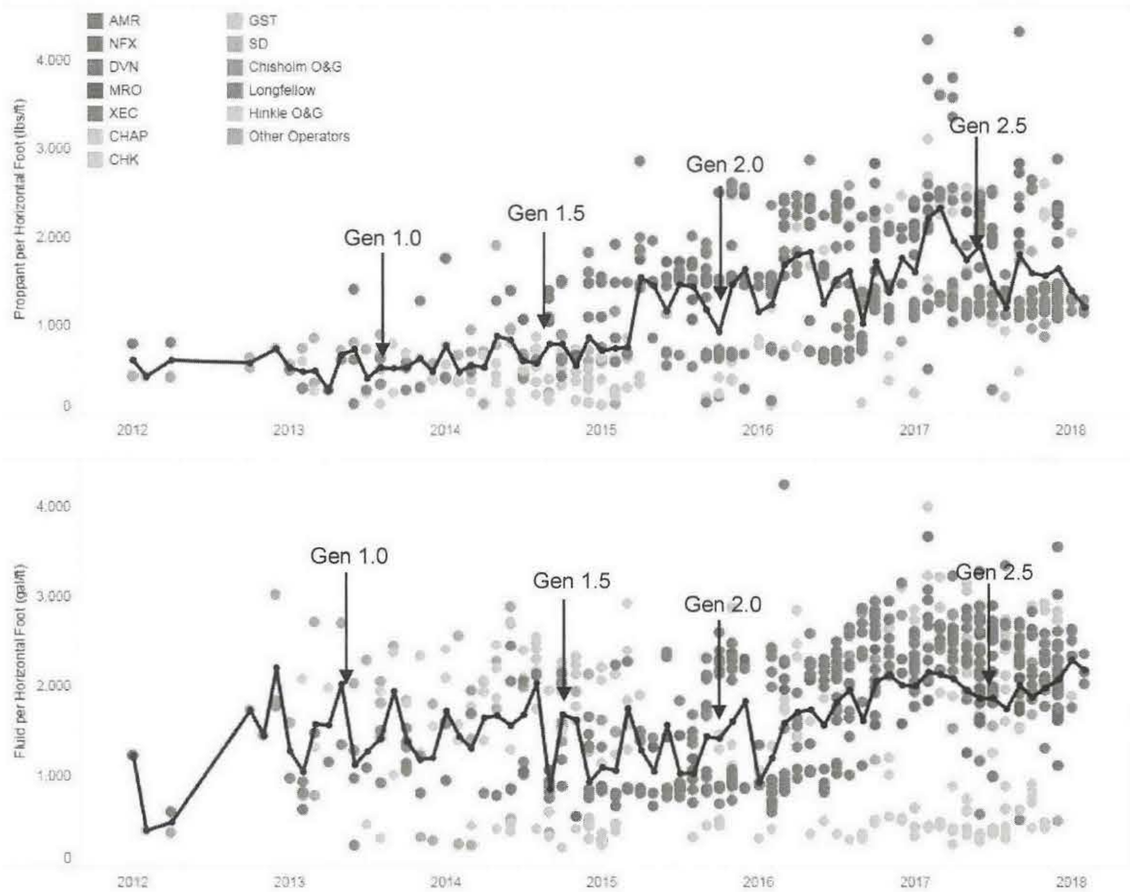


Source: Company Presentations, FracFocus, DrillingInfo

Completion Intensity Evolution in Kingfisher County by Operator

AMR's current proppant loading is ~50% lower than other major operators, while its current fluid loading is in line with other operators in the STACK play. AMR is also using more commoditized and low-cost proppant. All of these contribute to a lower completion cost.

STACK Completion Design Evolution by Operator



Source: Company Presentations, FracFocus, DrillingInfo

AMR's Current Density Assumptions Are Conservative as Industry Does the Heavy Lifting This Year

In the STACK play, operators are still actively testing down-spacing potential to find the optimal development plan per section. Recently, the conversation in the play has shifted to finding the optimal IRR or NPV for single section, rather than for single well. AMR has conducted 7 spacing test pilots across its acreage. The current base case scenario appears reasonable (14 wells total: 8 Osage wells, 4 Meramec wells and 2 Oswego wells per section) and even conservative compared to its peers in the STACK, in our view.

- CLR has conducted 6 full-unit tests in the over-pressured oil window and one half-unit test in the condensate window. Recently, the company introduced the preliminary economic model for unit development in the STACK Meramec over-pressured oil window. Initial results indicate that 4 wells per zone on average will deliver the maximum PV-10 from a single Meramec reservoir in a unit. The company's unit economic model includes a total of 8 wells with 4 wells in 2 Meramec reservoirs underlying its acreage in the over-pressured oil window.

- DVN's Showboat development is testing 4 landing zones within the Meramec and Woodford formations, with 6 wells across 2 landing zones in the Upper Meramec, 6 wells across 1 landing zone in the Lower Meramec, and 1 well across one landing zone in the Woodford, per drilling unit. This spacing test is in the volatile oil window.

- MRO's third and farthest east infill spacing pilot, 'Eve', in Kingfisher County's black oil window, averaged 30-day IP rates from the 5 new wells of 715 boepd (65% oil, 5,000').

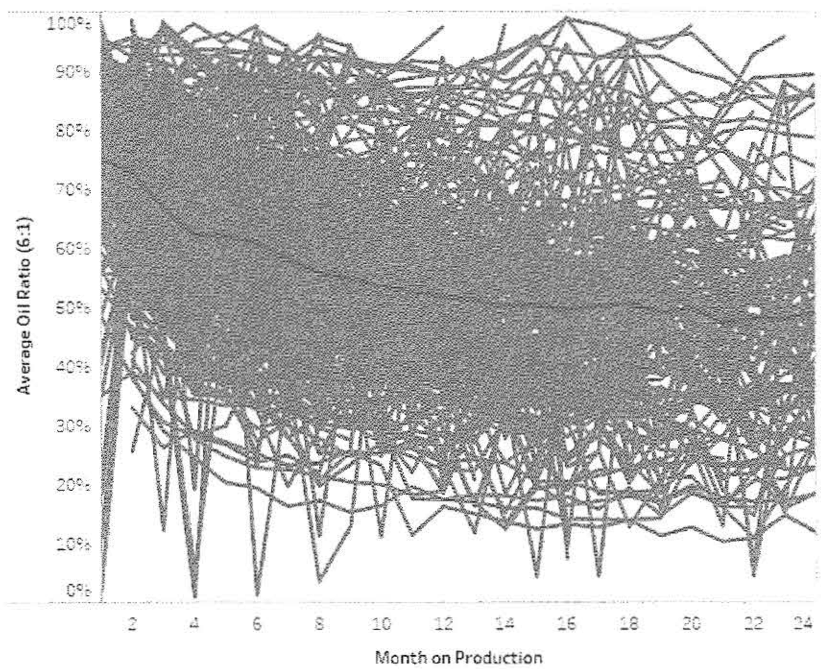
- NFX's most "technically comprehensive" spacing pilot, Velta June is testing 12 wells per section (3 wells in Upper Meramec, 6 wells in Middle Meramec and 3 wells in Lower Meramec), with average IP-30 of 1,195 boepd (68% oil, 5,000').

- XEC's Clyde-Copeland density pilot is testing the equivalent of 16 and 20 wells per section in the Woodford formation. XEC's Leon Gundy Pilot tested the equivalent of 19 wells per section across the Woodford, Osage, and Meramec formations.

GOR Should Not Be an Issue

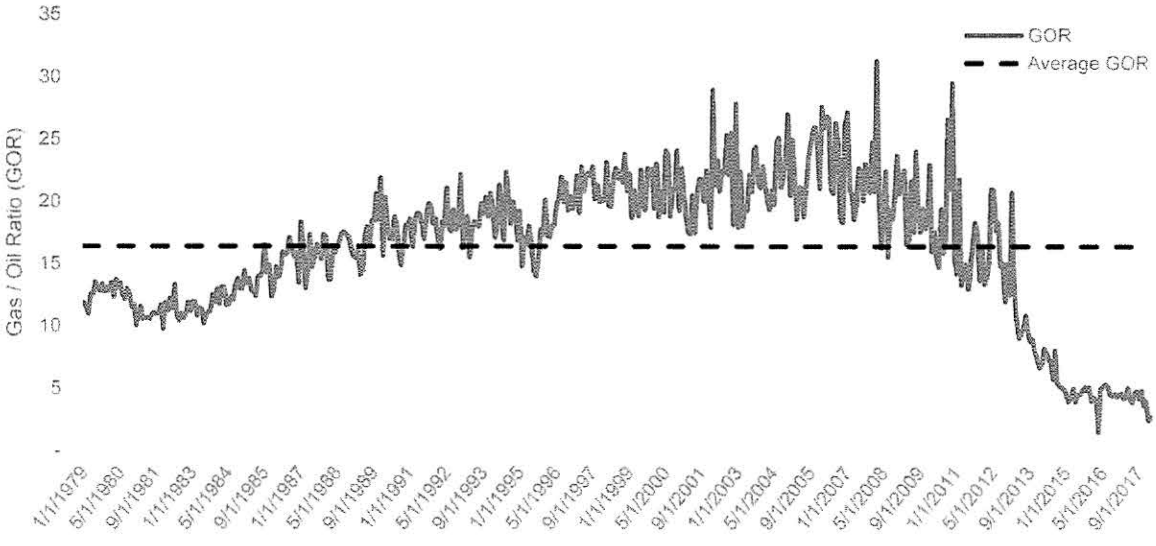
We believe investors have concerns with the Gas/Oil Ratio (GOR) in new oil basins as well as mature oil basins, especially where there are concerns with historical drainage from vertical development. When we look at wells drilled in Kingfisher County in 2015 with two years of production history, we don't see cause for concern. On average, GOR and oil rates appear to stabilize after the first 2 years. Some operators are seeing a bit more of a decline in oil ratio than others, but still mostly look to be within the ranges of company guidance. We will continue to monitor change in GOR as more production history is available and more wells are drilled.

AMR Well First 24-months GOR Distribution



Source: DrillingInfo, Guggenheim Securities, LLC Estimates

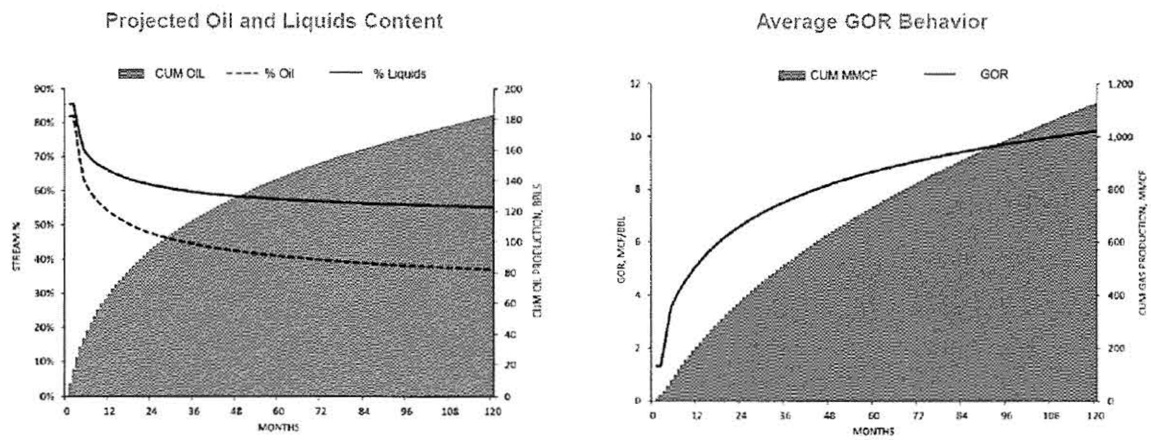
GOR of Aggregated Production in Kingfisher County, OK (1979-2017)



Source: DrillingInfo, Guggenheim Securities, LLC Research

Sample data on well LNU17N06W02A, from AMR's audited reserve report shows, ~57% of the oil, 38% of the natural gas liquids, and 38% of the natural gas are produced in the first five years of the life of the well. The GOR increases over time with month one at ~1 mcf/bbl, month twelve at ~5 mcf/bbl, and month sixty at ~8 mcf/bbl. GOR is estimated to peak at 10 mcf/bbl in years 6 - 8. In terms of oil ratio as a percent of production, in the first month, 2-stream production from the well is 82% oil (3-stream is 85% liquids assuming 16% shrink). In year one, 2-stream production from the well is 66% oil and 3-stream production is 70% liquids. The well breaches the 2-stream 50% oil point near the end of year 2 and 3-stream production remains above the 50% liquids point for the life of the well.

AMR Average GOR



Source: Company Fillings

Setting New Company Records in Kingfisher County

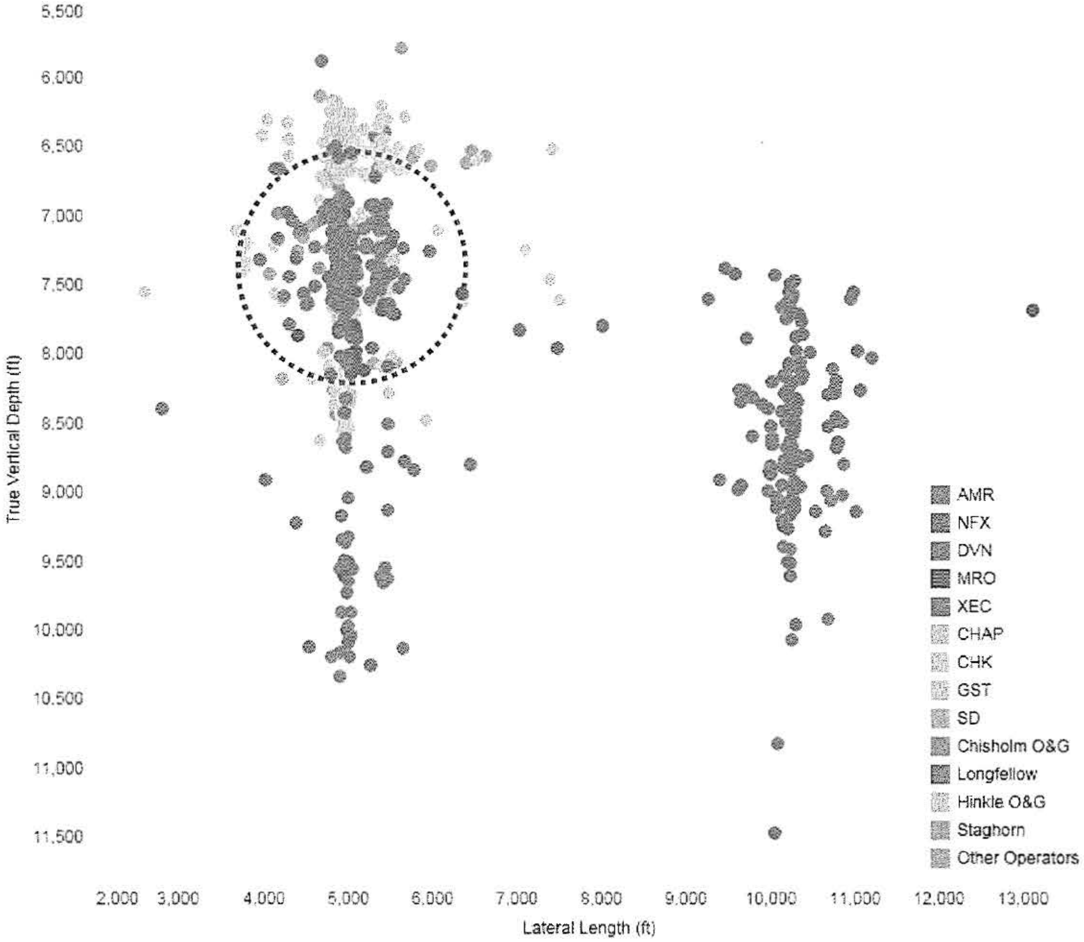
AMR is setting records in the Osage. In 3Q17, the Towne 1806 1-31MH well achieved an ip-30 of 158 bopd/1,000' (76% oil), beating its Osage type curve by ~40%. In 4Q17, AMR broke the record with the Walrus 1506 1-36MH that achieved an IP-30 of ~162 bopd/1,000' (90% oil). All the wells were drilled in the Osage formation. The proppant intensity of the wells was similar at ~1,200 lbs./ft. but improvements in geo-steering and lateral targeting are the main drivers of the outperformance.

Recent AMR Well Results

Well Name	Producing Interval	Lateral Length	Proppant/Ft	IP30 Oil per 1,000'
Bunker Buster 1606 1-13MH	Osage	4,853	1,386	203
Walrus 1506 1-36MH	Osage	5,106	1,161	162
Towne 1806 1-31MH	Osage	4,834	1,445	158
Sadiebug 1606 1-35MH	Osage	4,820	1,290	153
Old Crab 1506 1-24MH	Osage	4,765	1,268	142
McNulty 1806 1-33MH	Osage	4,818	1,178	129
Aberfeldy 1605 4-16MH	Osage	4,756	1,288	127
EHU 216H	Osage	5,321	1,263	125
Oltmanns 1805 6-14MH	Osage	4,930	1,377	123
Mouse Rat 1605 1-9MH	Osage	5,431	1,148	114
Copperplate 1605 1-3MH	Osage	4,148	1,309	111
McLovin 1605 1-6MH	Osage	4,182	1,422	107
Aces High 1606 4-11MH	Osage	4,776	1,325	105
Farrar 1806 1-32MH	Osage	4,787	1,413	104
Maly 32-M1-H	Osage	4,768	1,816	101
Bugabago 2006 1-31MH	Osage	4,774	1,339	100
Edwin 1805 4-22MH	Osage	4,259	1,258	100
Oak Tree 1605 2-30MH	Meramec	4,744	999	145
Dalwhinnie 1605 1-31MH	Meramec	4,812	3,696	102
Huntsman 1506 2-23MH	Meramec	4,558	1,388	100
Yellowstone 1505 4-8MH	Meramec	4,730	1,291	94
Samuel 1505 1-29MH	Meramec	4,862	1,311	88
Red Queen 1506 1-1MH	Meramec	4,078	1,293	85
Dixon 1505 3-16MH	Meramec	4,858	1,014	80
Three Wood 1505 4-17MH	Meramec	4,634	1,470	80
Helen 1605 5-33MH	Meramec	4,620	757	73
Cheshire Cat 1506 1-13MH	Meramec	4,655	1,315	70
Huntsman 1506 4-23MH	Meramec	4,766	1,323	63
Martin 1505 4-9MH	Meramec	4,795	994	52
Ray 1605 3-27MH	Meramec	4,833	704	43

Source: Company Presentations, FracFocus, DrillingInfo

TVD and Lateral Length Distribution in Kingfisher County by Operator

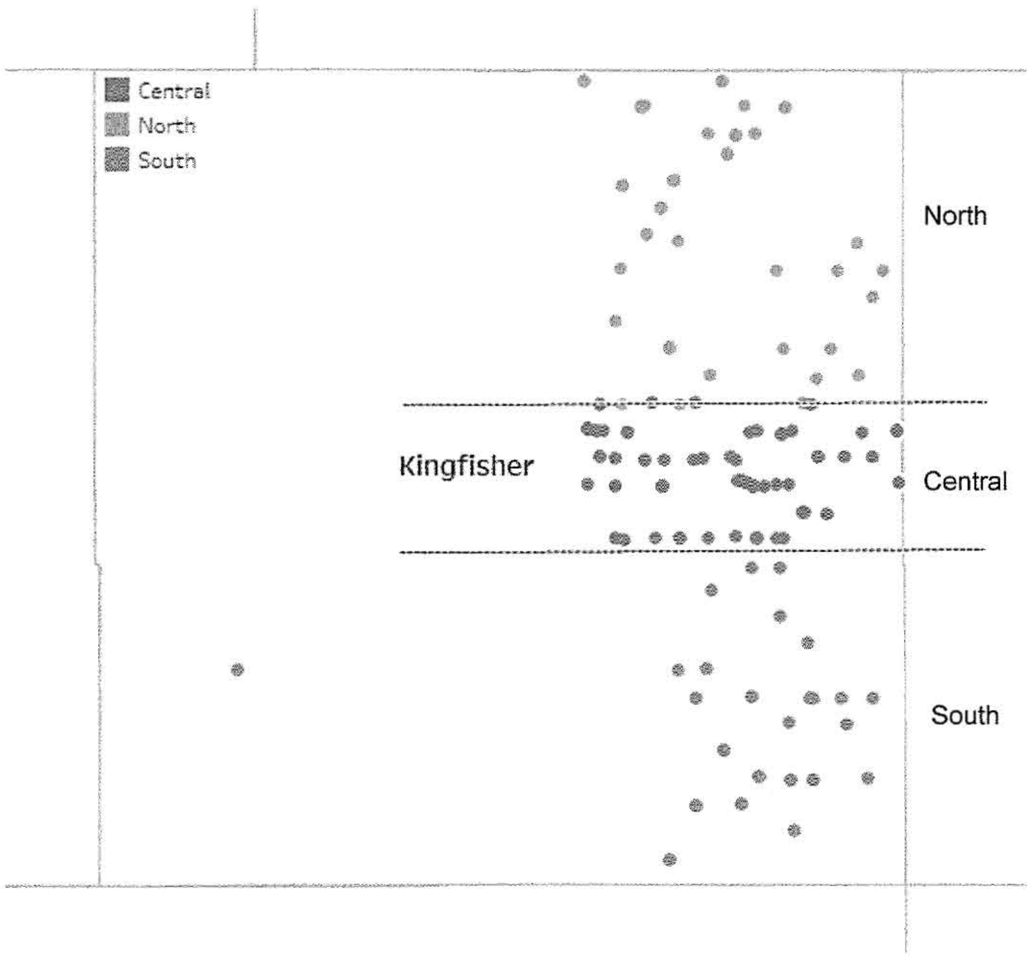


Source: FracFocus, Company Presentations, DrillingInfo, Guggenheim Securities, LLC Estimates

TYPE CURVES / PRODUCTIVITY BY AREA

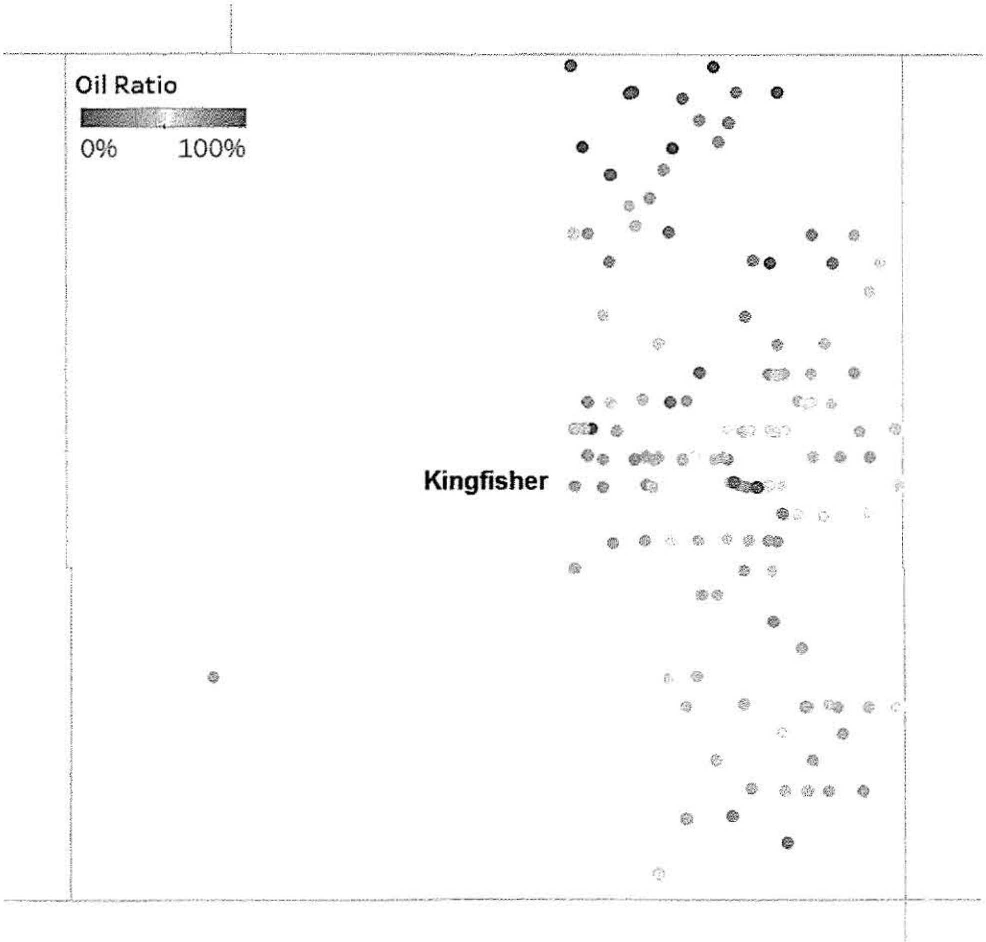
We analyzed well results and modelled type curves by well location and producing interval. AMR's 110,000-acre position in Kingfisher County can be divided into 3 type curve areas: North, Central and South. We built 4 type curves for the Kingfisher acreage based on the area and producing interval: North Kingfisher Osage, Central Kingfisher Osage, South Kingfisher Osage, and Kingfisher Meramec. The company type curves assume a lateral length of 4,800' in all areas. Current well costs are ~$4.0 million per well for 4,800' lateral wells. A map of the areas as well as tables detailing the type curves by area can be found below.

AMR Type Curve Area Map



Source: Company Presentations, DrillingInfo, Oklahoma Corporation Commission, Guggenheim Securities, LLC Estimates

AMR Oil Ratio Map

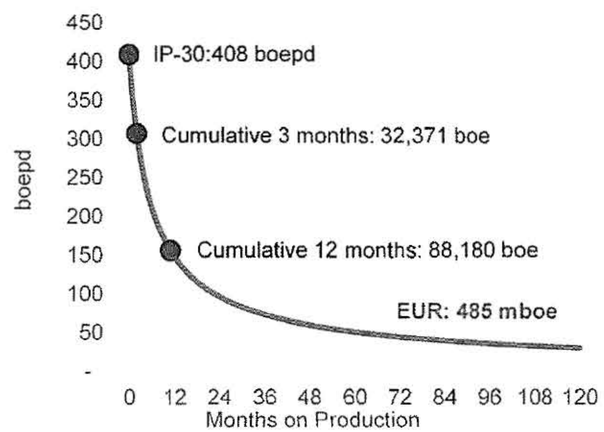


Source: Company Presentations, DrillingInfo, Oklahoma Corporation Commission

North Kingfisher Osage Type Curve

We analyzed 34 wells across the company's northern Kingfisher acreage, completed since 2015 with sufficient production history. We focused on 2016 and 2017 vintage wells, as completion intensities are significantly different. The North Kingfisher Osage wells exhibited an average recovery (3-stream production) of 485 mboe (51% oil, 4,800 ft. lateral).

AMR North Kingfisher Osage Production Curve (Normalized to 4,800')



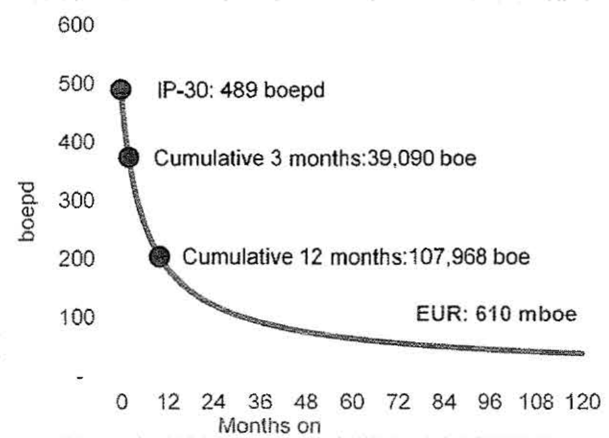
	Henry Hub Price			
	$2.50	$3.00	$3.25	$3.50
$75	79%	85%	88%	91%
$65	53%	58%	60%	62%
$55	32%	36%	38%	40%
$45	16%	19%	20%	22%

Source: Oklahoma Corporation Commission, Oklahoma Tax Commission, DrilingInfo, Guggenheim Securities, LLC Estimates

Central Kingfisher Osage Type Curve

We analyzed 39 wells across the company's central Kingfisher acreage, completed since 2015 with sufficient production data. We focused on 2016 and 2017 vintage wells, as completion intensities are significantly different. The Central Kingfisher Osage wells exhibited an average recovery (3-stream production) of 610 mboe (48% oil, 4,800 ft. lateral).

AMR Central Kingfisher Osage Production Curve (Normalized to 4,800')



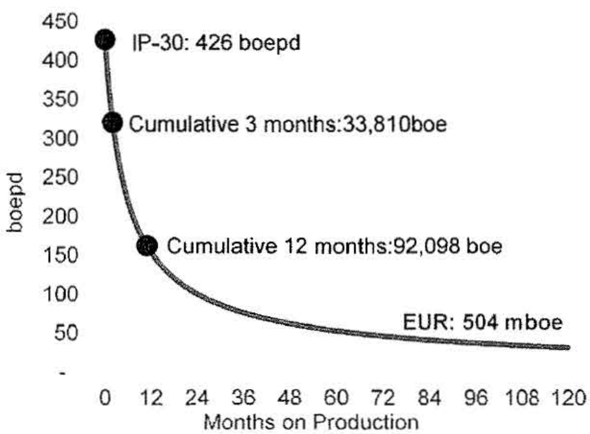
	Henry Hub Price			
	$2.50	$3.00	$3.25	$3.50
$75	126%	137%	142%	148%
$65	86%	94%	98%	102%
$55	55%	61%	64%	68%
$45	31%	36%	38%	41%

Source: Oklahoma Corporation Commission, Oklahoma Tax Commission, DrilingInfo, Guggenheim Securities, LLC Estimates

South Kingfisher Osage Type Curve

We analyzed 21 wells across the company's southern Kingfisher acreage, completed since 2015 with sufficient production data. We focused on 2016 and 2017 vintage wells, as completion intensities are significantly different. The South Kingfisher Osage wells exhibited an average recovery (3-stream production) of 504 mboe (46% oil, 4,800 ft. lateral).

AMR South Kingfisher Osage Production Curve (Normalized to 4,800')



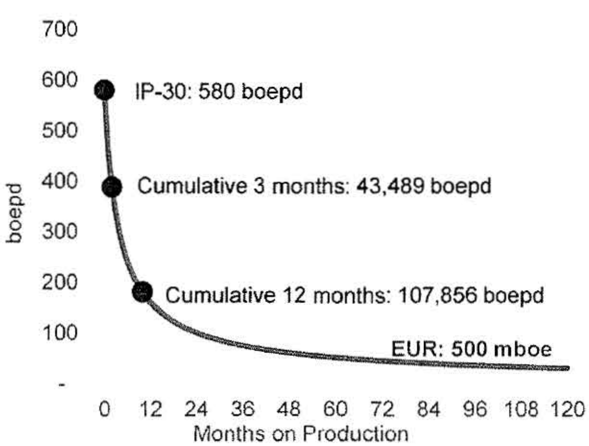
	Henry Hub Price			
	$2.50	$3.00	$3.25	$3.50
$75	86%	93%	97%	101%
$65	59%	64%	67%	70%
$55	36%	41%	44%	46%
$45	NEG	NEG	NEG	NEG

Source: Oklahoma Corporation Commission, Oklahoma Tax Commission, Drilinglnfo, Guggenheim Securities, LLC Estimates

Kingfisher Meramec Type Curve

We analyzed a few well results from AMR and some results from offset operators including CHAP, MRO, and NFX on the Anadarko Shelf, in the normal-pressured oil window. We estimate that AMR recovers 500 mboe (50% oil, 4,800', 3-stream). We expect the results will improve as more AMR Meramec wells appear in public records. Our type curve will tend to underestimate actual EUR's because we can't adjust for downtime associated with pad completions and lift optimization. Also leading edge results have improved every year whereas our type curve equal-weights earlier vintage wells.

AMR Kingfisher Meramec Production Curve (Normalized to 4,800')



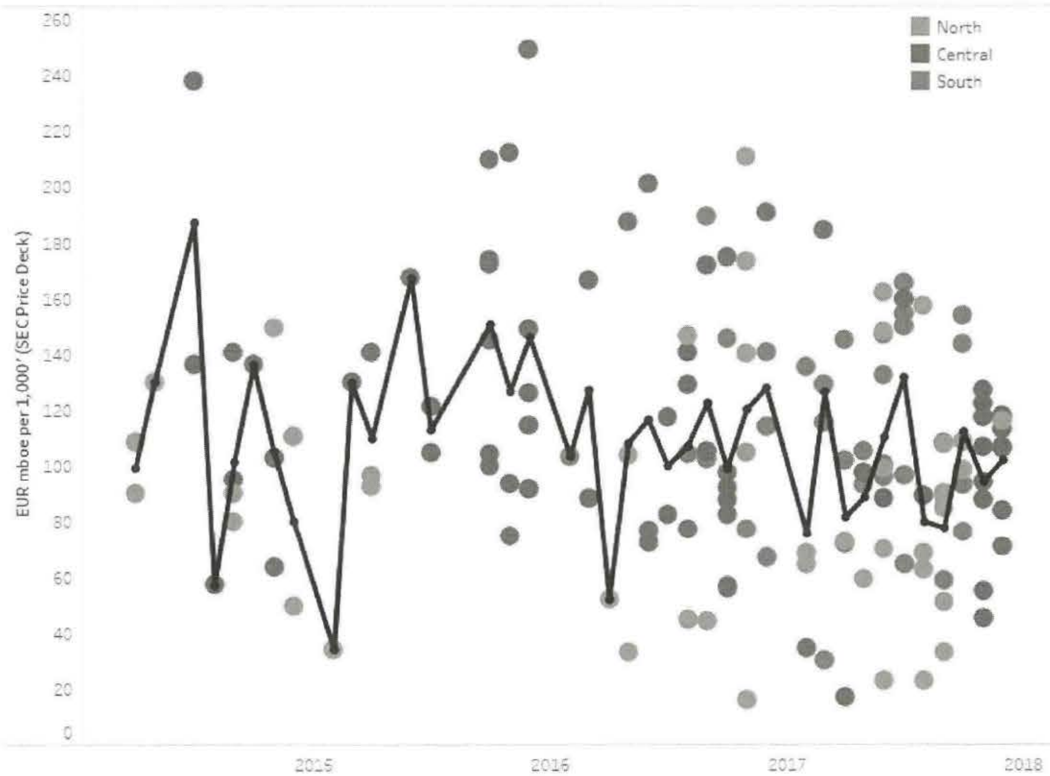
	Henry Hub Price			
	$2.50	$3.00	$3.25	$3.50
$75	128%	139%	144%	150%
$65	82%	90%	94%	99%
$55	49%	55%	58%	61%
$45	NEG	NEG	NEG	NEG

Source: Oklahoma Corporation Commission, Oklahoma Tax Commission, Drilinglnfo, Guggenheim Securities, LLC Estimates

EUR Distribution by Type Curve Area

We believe AMR has been transparent on well results. The company released EUR (Estimated Ultimate Recovery) estimates from YE17 audited reserve report for most of its wells. Overall, due to more recent activity in the North and South areas, which have lower productivities compared to the Central area, the EURs are trending down and averaged above 100 mboe/1,000' under 2017 SEC pricing ($51.34/bbl oil, $2.98/mcf gas). AMR ranks favorably among STACK producers considering a low D&C cost, fast cycle times and a rapid 'half-life' for oil production.

AMR EUR Distribution



Source: Company Presentations, DrillingInfo, Guggenheim Securities, LLC Estimates
Notes: SEC EUR YE17 was audited by Ryder Scott & Co; SEC Prices: $53.49/bbl, 3.00/mcf; Oil Gas conversion ratio 6:1

FINANCIAL SUMMARY

Outspend May Peak This Year but Is Not a Burden Considering AMR's Low Leverage

In 2018, AMR expects to spend two-thirds of its total $750mm - $800mm budget, or ~$500mm on upstream and most of the balance on midstream. The program will drill 170-180 gross wells and maintain a 'drilled uncompleted' (DUC) inventory at 20-25 wells. To accomplish this program, the company will run 8 rigs through year end of 2018 and may add one more rig at the end of 2018. We expect the upstream capex budget will rise to $670mm - $700mm in 2019 and $750mm in 2020 to deliver 67% CAGR of oil growth and support growth at Kingfisher Midstream. The outspend should peak this year at ~$400mm, by our estimate. AMR had a ~$200mm working capital surplus in 1Q, minor bank debt and a single bond issue with a 2024 maturity. As a result, we don't expect the outspend will be a significant burden as we estimate leverage will peak at 1.4x debt/ebitda by YE2018 before AMR begins to achieve free cash flows.

Cimarron Express Pipeline Project Enhances AMR's Midstream Capacity

KFM owns a 50% stake in the Cimarron Express Pipeline project, a JV between KFM, Blueknight Energy Partners, and Ergon. Cimarron Express originates in Kingfisher County, OK, and connects to Blueknight's crude oil terminal at Cushing, OK. It has an initial capacity of 90,000 b/d, expandable to more than 175,000 b/d. The pipeline is expected to be completed by mid-2019.

Under the JV, Blueknight would build and operate Cimarron Express and continue to operate its existing crude oil storage facilities at Cushing. A receipt terminal for the new pipeline will be built at KFM's crude oil storage facility in northeastern Kingfisher County. Cimarron Express would also connect to KFM's crude oil gathering system and truck unloading facilities. AMR has agreed to an acreage dedication of 120,000 net acres in Kingfisher and Garfield Counties.

From an upstream perspective, the Cimarron Express pipeline enables AMR and other STACK producers to maximize the value of their crude oil production. From a midstream business perspective, we also see long-term value in this pipeline, as it enables KFM to aggregate STACK oil volumes on their crude gathering system to deliver to Cimarron Express.

Capex Levels Should Rise Through 2020

We estimate ~$690mm upstream capex in 2019, and ~$790mm in 2020 compared to ~$565mm in 2018 (including non-D&C capex) as AMR ramps from 8 rigs currently to a peak rig count of 10-11 by late 2020. We expect rigs to be added every 12 months. Inflation could run 10% - 15% in 2018, by our estimates, but that is incorporated into our capex forecast.

EPS Estimates

Our EPS estimates for 2018 / 2019 and 2020 are $0.39 / $1.04 and $1.54, respectively. This compares to consensus estimates of $0.43 / $0.95 and $1.16, respectively. The main driver of EPS growth is production, which we estimate will increase 70% / 84% and 48%, respectively. EBITDA margins should improve as well from 56% in 2017 to 79% in 2020, by our estimates, but an inflationary cost environment will not allow full absorption of higher commodity prices into earnings.

Company Milestones

- In January 2016, Alta Mesa Holdings entered into a Joint Development Agreement with Bayou City Energy Partners for a 40-wells Drill-co program. This deal helped Alta Mesa to convert more than 14,000 acres to Held-By-Production (HBP) status. The Drill-co deal shows the strength of Alta Mesa's asset and the high degree of confidence that Bayou City Energy has on Alta Mesa's management team, in our view.

- In November 2016, Silver Run Acquisition II Corporation was incorporated as a blank check company, formed by Riverstone Holdings.

- In March 2017, Silver Run II Acquisition II (**SRUN**), a special purpose acquisition company, completed its IPO, which generated net proceeds of $1.035 billion.

- In July 2017, Alta Mesa added ~20,000 net acres in Major and Blaine counties.

- In August 2017, Silver Run Acquisition Corporation II announced that it had entered into definitive agreements to combine with Alta Mesa Holdings, LP and Kingfisher Midstream, LLC.

- On 2/9/2018, Alta Mesa Resources Inc. became a publicly traded company, as a result of the business combination of Silver Run Acquisition Corporation II, Alta Mesa Holdings LP and Kingfisher Midstream LLC. The combined company was renamed to Alta Mesa Resources Inc. and its shares began trading under the ticker of **AMR** on NASDAQ.

- On 5/10/2018, Kingfisher Midstream (KFM), Blueknight Energy Partners, and Ergon, announced the execution of definitive agreements to form Cimarron Express Pipeline, LLC. KFM will own a 50% stake of Cimarron Express, which would originate in Kingfisher County, OK, and connect to Blueknight's crude oil terminal at Cushing, OK.

INVENTORY DEPTH

AMR's Base Case Inventory Assumptions Are Conservative

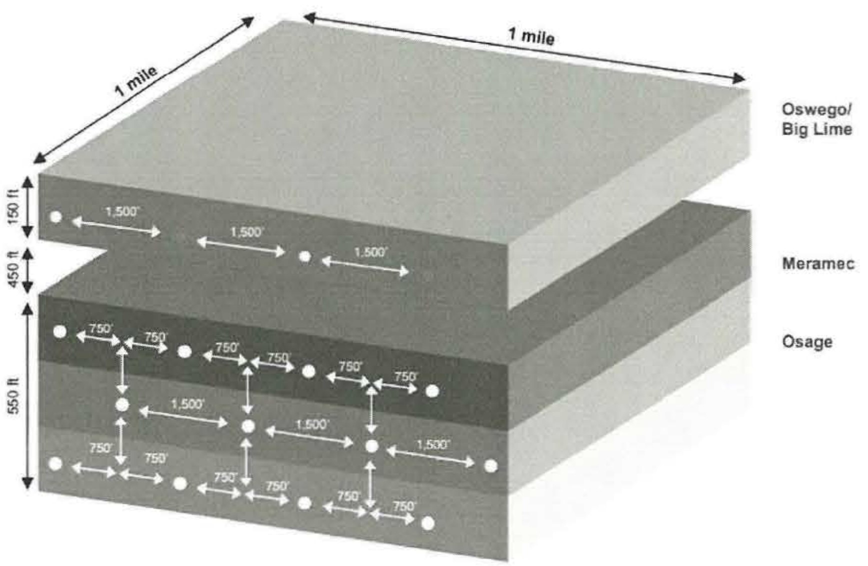
Inventory depth or inventory life is the primary focus of E&P companies. AMR has a relatively high PUD ratio of 70%, which means a fair amount of their future drilling locations have been booked as proved reserves. But we believe the "probable" inventory, or reserves remaining to book assuming some level of certainty, is large. We conservatively estimate that the reserves remaining to book are 2x the reserves already booked as proven at YE2017. This gives credit for only the Osage and Meramec in just 50% of the company's Kingfisher acreage and 25% of the Major County acreage. AMR has at least 8 years drilling inventory based on these conservative estimates. Over time, we expect the inventory to expand as the company recently started to test the Manning Limestone formation in northern Kingfisher County and is in the very early stages of testing Major County.

AMR's Base Case Inventory Estimate By Formation (Gross)

Formations	Operated Gross Locations	Non-Operated Gross Locations	Total Gross Locations	Inter-well Spacing per Interval	Intervals per Section
Osage	1,196	1,252	2,448	1,320'	2
Meramec	676	588	1,264	1,320'	1
Oswego	203	281	484	2,640'	1
Total	2,075	2,121	4,196		

**Note: Company estimate as of YE17*

Base Case Development Concept



Source: Company Presentations

Guggenheim Inventory Estimate (Net)

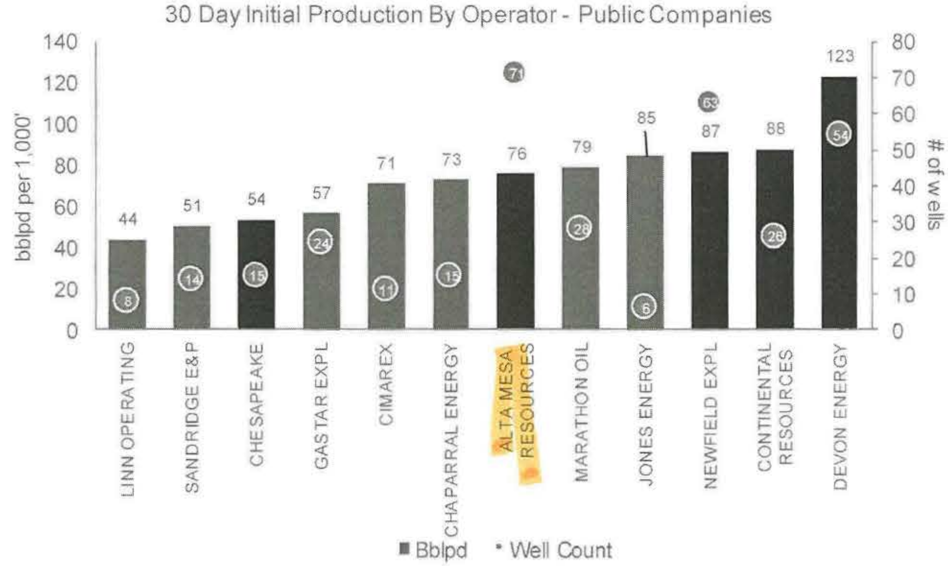
		% Could Work	% WI	Spacing *(acres)*	Risked Locations *(net)*	(mboe) Reserves per location	(mboe) Net Resource Potential
Kingfisher County							
Osage	141,026	50%	78%	80	688	508	349,250
Meramec	141,026	50%	78%	160	344	510	175,313
Oswego	141,026	0%	78%	320	-	240	-
Big Lime	141,026	0%	78%	320	-	240	-
Manning	141,026	0%	78%	320	-	240	-
Hunton	141,026	0%	78%	320	-	240	-
Woodford	141,026	0%	78%	320	-	240	-
Chester	141,026	0%	78%	320	-	240	-
Cherokee	141,026	0%	78%	320	-	240	-
Kingfisher Potential					1,031		524,563
Major County							
Osage	25,641	25%	78%	160	31	508	15,875
Meramec	25,641	25%	78%	320	16	510	7,969
Oswego	25,641	0%	78%	320	-	240	-
Big Lime	25,641	0%	78%	320	-	240	-
Manning	25,641	0%	78%	320	-	240	-
Hunton	25,641	0%	78%	320	-	240	-
Woodford	25,641	0%	78%	320	-	240	-
Chester	25,641	0%	78%	320	-	240	-
Cherokee	25,641	0%	78%	320	-	240	-
Major Potential					47		23,844

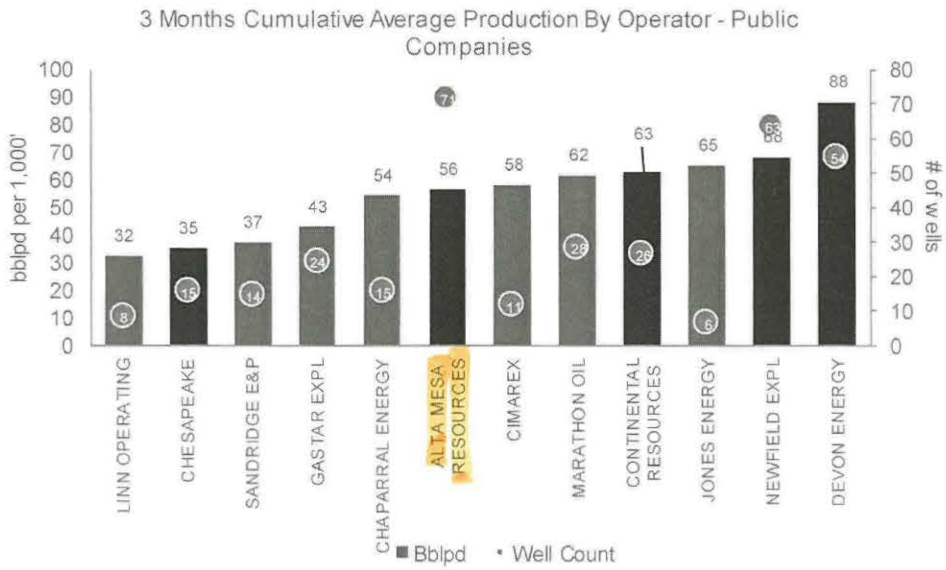
Source: Company Filings, Guggenheim Securities, LLC Estimates

Cost Advantage Enables AMR to Post the Lowest Breakeven in the STACK

Although AMR's wells look average based on peak ip-30/1,000' and cume 3-month/1,000' of oil volumes in the STACK play over the past 18 months, AMR has posted the lowest D&C costs among STACK operators due to lower completion intensity and shallower vertical depths. From a well return perspective, we believe AMR competes favorably with STACK producers.

STACK Producer Ranking by Well Productivity



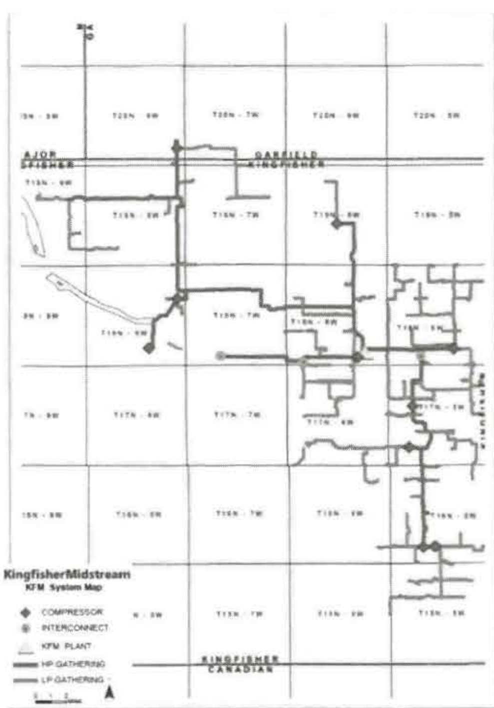


Source: Company Presentations, DrillingInfo, Guggenheim Securities, LLC Estimates

MIDSTREAM

Alta Mesa/Kingfisher Midstream – Embedded within AMR Now but Likely to Be Spun-out. Even though AMR/KFM is a new company on public investors' radar, they have been operating in the STACK for 30 years. For now, Kingfisher Midstream is embedded within the E&P entity, but management has stated that they expect to IPO this business, probably in 2019, and have been making the management hires to do so. The midstream IPO window has been closed lately but we believe KFM is in a financial position to be patient, though at some point we think E&P investors will want a path to midstream monetization, given overall trends in the industry away from complicated business structures. If we do see any IPO comps soon, it will likely have an impact on Kingfisher deal size/structure – especially as it relates to IDRs. The company has laid out aggressive organic growth expectations on both the E&P and midstream sides, but views midstream capabilities as an integral part of their value offering, and we would expect some forays into M&A once they have their footing in public markets. But overall, they expect to remain a STACK (or close to it) pure-play.

Kingfisher Midstream System



Natural Gas Processing	• Current processing capacity of 350 Mmcf/d, inclusive of offtake agreements and 200 Mmcf/d Cryogenic plant in startup • 1,200 Bbl/d condensate stabilizer	
Low Pressure Pipeline	• ~309 miles of low-pressure crude and gas gathering lines[1] • Natural gas gathering: 4"-16" pipeline • Crude gathering: 6"-12" pipeline	
High Pressure Pipeline	• ~104 miles of 4"-16" rich gas transportation pipeline[2] • Average operating pressure of 1,100 psig and piggable • 4 miles of 12" residue gas pipeline to PEPL • 9 miles of 16" residue gas pipeline to OGT • 4 miles of 6" NGL Y-grade pipeline, with 13,000 Bbl/d capacity to Chisolm Pipeline	
Compression Facilities	• Field Compression:	• 17 CAT 3516s (23,460 total HP)[3] • 3 CAT 3508s (2,070 total HP) • 1 CAT 3306 (203 HP)
	• Inlet Compression:	• 6 CAT 3606s (10,650 total HP)
	• Residue Compression:	• 3 CAT 3516s (4,140 total HP) • 5 CAT 3608s (12,500 total HP)[4]
Other Infrastructure	• 50,000 Bbl crude storage with 6 truck loading LACTS • 3 NGL bullet tanks: 90,000 gallon capacity	
Producer Connections	• 162 meters settled through December 2017	

Source: Company Presentation

Midstream Asset Valuation: $1.75bn Range (Midpoint). From a valuation perspective, we estimate Kingfisher Midstream (as currently structured) is worth around $1.5-2.0bn. This is based on a couple different methodologies, but we estimate KFM can generate ~$175mm of EBITDA by 2020. The Natural Gas/NGL peer group trades at 9.5-10.5x 2020E EBITDA, and we think at a minimum KFM should trade in line with the group and perhaps at a 1-2x turn premium based on their growth outlook. So 10x $175mm EBITDA is $1.75bn midstream valuation, with very little debt attached to KFM currently ($62.5mm outstanding under a $300mm revolver). We think 30-40% annual EBITDA growth over the next 3-4 years is a reasonable assumption, which is well-beyond peers — though we think investors right now are in a "show me" mindset with regard to aggressive development, and midstream investors are less inclined to pay a large up-front multiple for "hockey-stick" growth than they would have been a couple years ago. We also note that the way the spin-out or IPO is structure could change the valuation, depending on what assets are included, whether they lever up KFM, or numerous other considerations.

Kingfisher Midstream Segment Details

Segment details FY December; USD in millions except per-share items	Q1 Mar-18	Q2E Jun-18	Q3E Sep-18	Q4E Dec-18	2018E	2019E	2020E
Total Gross Margin	**17**	**23**	**26**	**32**	99	152	174
G&P Gross Margin	17	23	26	32	99	124	132
Crude/NGL Gross Margin	-	-	-	-	-	2	6
Water Gross Margin						25	36
Gross margin natural gas ($/mmbtu)	$1.52	$1.52	$1.52	$1.52	$1.52	$1.36	$1.24
Gross margin crude/NGL ($/bbl)	-	-	-	-	-	**$0.45**	**$0.45**
Gross margin water ($/bbl)	$0.90	$0.90	$0.90	$0.90	**$0.90**	**$0.90**	**$0.90**
Operating Expenses	1.8	2.7	3.1	3.7	11.4	17	20
per mmbtu	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Operating Statistics							
Inlet Volumes (MMcf/d)							
Alta Mesa	80	95	105	120	100	136	165
3rd Party	21	55	65	85	57	92	103
Other						-	-
Total Inlet Volumes	**101**	**150**	**170**	**205**	**157**	**227**	**268**
Capacity					370	370	370
Utilization					*42%*	*61%*	*72%*
AMR Volume Growth						*36%*	*22%*
Third Party Volume Growth						*62%*	*13%*
Throughput for crude/NGL assets (KBbls/d)							
Cimarron Volumes						26	70
Crude Gathering Volumes						-	-
Total throughput for crude/NGL assets	-	-	-	-	-	**26**	**70**
KFM Ownership of Cimarron						*50%*	*50%*
Throughput for Water assets (KBbls/d)							
Oil Production (Net)	13	17	21	25	19	36	52
Working Interest	*52%*	*56%*	*60%*	*75%*	*61%*	*81%*	*82%*
Oil/Water Ratio	1.75	1.75	1.75	1.75	1.75	1.75	1.75
Total throughput for Water assets	**43**	**54**	**62**	**58**	**54**	**77**	**111**

Source: Company Filings, Guggenheim Securities, LLC Estimates

G&P Upside: Even with just AMR volumes, KFM has a robust growth profile, but winning 3rd party business is a big piece of their strategy. Current 2018 guidance has 3rd party business at ~36% of 2018 volumes and we forecast they will maintain that percentage as volumes grow in the basin. On a fee basis, we think current legacy contracts (signed in 2015) are at a higher level than current market rates (due to increased competition in the basin), so we have rates stepping down through 2020E, but this is more than offset by our volume growth estimates.

See pages 43 - 44 for analyst certification and important disclosures.

Water Upside: We think another underappreciated growth angle for KFM is their produced water business. Water takeaway is around 50k bpd now but we expect they can grow that significantly with both AMR growth and 3rd party business. The water cut in the STACK once stabilized is 2:1 or 1:1, so it's not as big of a logistical issue as the Delaware (where the cut can be 6:1 or more) but it still needs to be taken care of, and especially given the seismicity issues in the STACK, operators that know the geology have an advantage. Produced water is not currently embedded in KFM's guidance, but we estimate it could be a ~$40mm EBITDA business by 2020.

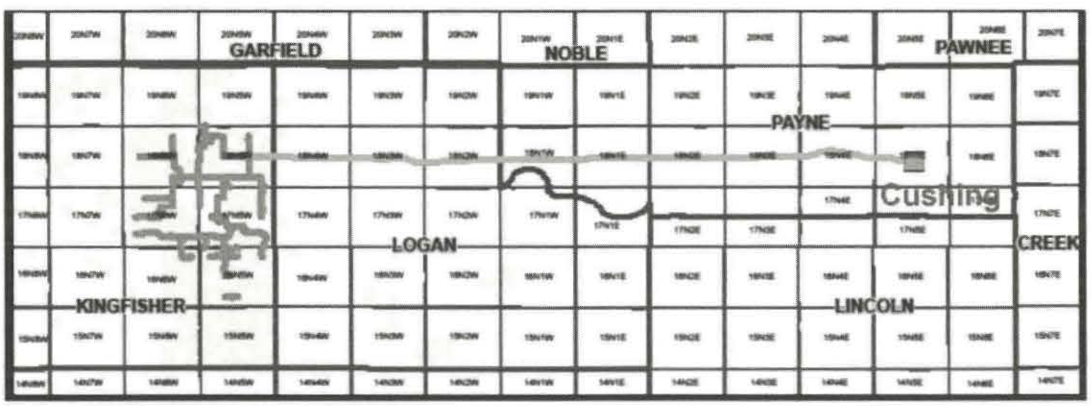
Kingfisher Midstream Assets

Pipelines and Storage: 400 miles of existing low and high pressure pipelines, 50,000 BBLs of crude storage, NGL storage and purchasing and marketing capabilities. In addition to the physical assets, Kingfisher Midstream also owns more than 200,000 Dth/d of firm transport residue pipeline capacity on nearby interstate pipelines.

Processing Capacity: In April 2018, Kingfisher commissioned a 200 mmcf/d cryogenic plant adjacent to the 60 mmcf/d plant resulting in a total processing and offtake capacity of 350 mmcf/d.

Cimarron Pipeline: In May 2018, Kingfisher Midstream announced a partnership to develop a long-haul crude pipeline project from the Kingfisher Midstream plant site to Cushing, OK. Kingfisher Midstream will have a 50% equity interest in the pipeline project, which will have an initial capacity of 90,000 barrels per day, expandable to over 175,000 barrels per day.

Cimarron Express Pipeline Route



Source: Company Presentation

5-FACTOR FRAMEWORK

	Risk Tolerance	Access to Markets	Growth Visibility	Potential Catalysts	Valuation	TOTAL
Ranking	3	2	3	2	2	12

We rank companies on a scale of 1-3, with 3 representing "above average", 2 "average", and 1 "below average."

Source: Guggenheim Securities Estimates

RISK TOLERANCE (3 – ABOVE AVERAGE)

DEBT METRICS. AMR has an enviable leverage position, in our view. We estimate a net debt/EBITDA ratio of 1.3x in 2Q18. Leverage should peak in 2018E and decline to 0.4x through 2020E as free cash flows commence in 2019E.

OUTSPEND. We estimate the peak outspend will be in 2018. We estimate capex of $750mm - $800mm against cash from operations of $385mm. The outspend could diminish dramatically through 1H19 before free cash flows are achieved by late 2019.

BANK DEBT. The company has a combined $700mm borrowing base for its upstream and midstream credit facilities. As of May 30, 2018, AMR has utilized ~$63mm of it. We also estimate a $196mm working capital surplus as of 1Q18 and $261mm of cash on hand. We believe the borrowings under the credit facility will peak in 3Q19E after which time the company should begin to generate free cash flows.

MATURITIES. The $500mm, 7 7/8% unsecured debt issue will mature December 15, 2024. The bonds were trading above par at $109.75 as of December 6, 2017. This is AMR's only long-term obligation.

HEDGES. AMR has hedged ~50% of projected oil production in 2H18 and 22% of projected oil production in 2019. Fixed price swaps cover for ~36% of the total hedged oil volumes. The remainder are covered by various option contracts. On the gas side, AMR has hedged about 45% of projected gas production in 2018 and 25% in 2019. Fixed price swaps cover ~40% of the total hedged volumes, balanced by various option and basis contracts. AMR does not have any NGL hedges.

OFF-BALANCE SHEET. None.

GROWTH VISIBILITY (3 – ABOVE AVERAGE)

At 1Q 2018, we estimate AMR had more than 200 (n) producing wells, representing less than 8% of their total risked inventory. In our model, we risked many intervals in the STACK that have been successfully tested by 3rd parties that could increase our inventory estimate once AMR deems it economically viable on their acreage.

POTENTIAL CATALYSTS (2 – AVERAGE)

The delineation of Osage and Meramec in Major County acreage and the delineation of Oswego, Manning in Kingfisher County could increase inventory by ~75%.

VALUATION (2 – AVERAGE)

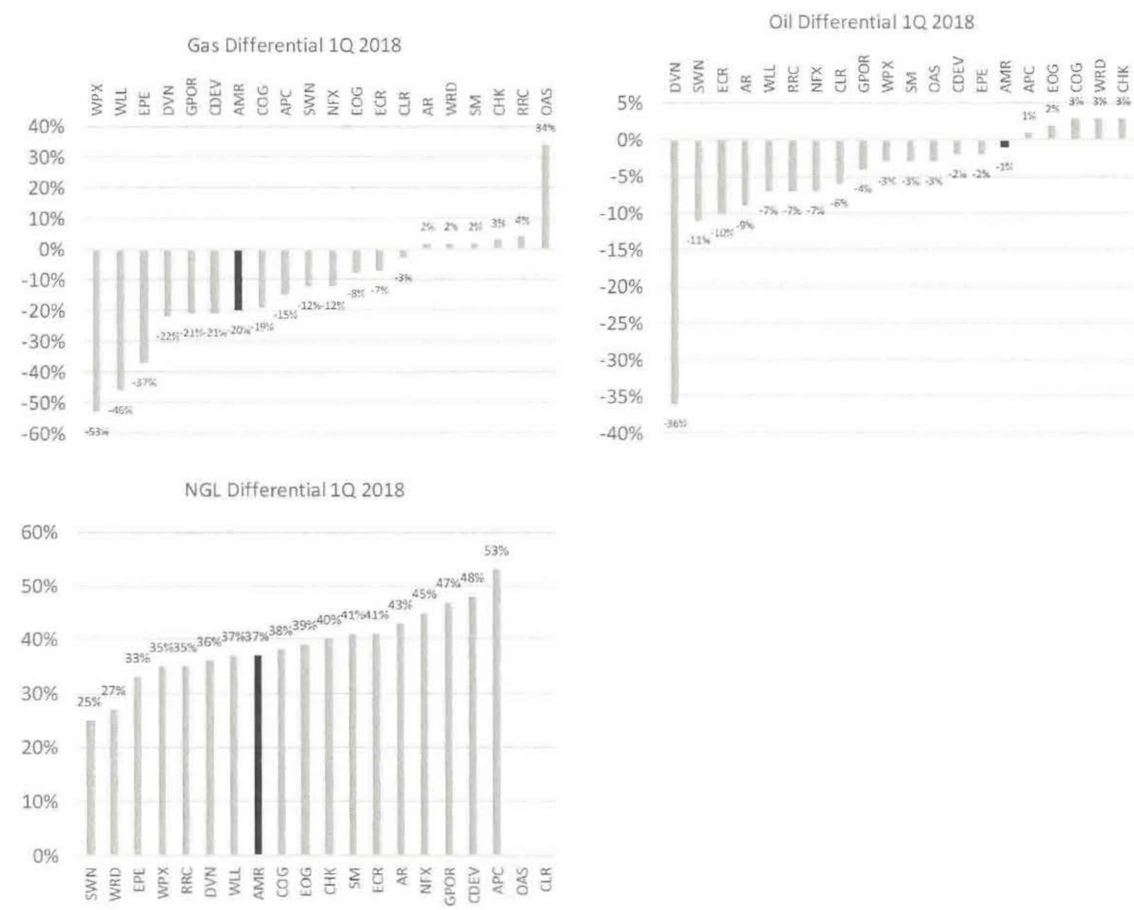
Our $10.00 PT/NAV estimate for AMR is based on our 2020 estimate of proved reserves (net of debt) and midstream value. Proved reserves (net of debt) represent two-thirds of our NAV estimate, or $6.50 per share, while the balance is midstream value. Based on our forecast for AMR's development activities, we estimate the company's proved reserve will grow by ~176% at YE20 from YE17 level, to 2.9 tcfe. Proved reserves are valued at $1.18 per mcfe, or ~$3.4bn, less ~$490mm of net debt. Our valuation for Kingfisher

Midstream of $1.7bn, is based on our estimate of 2020 midstream EBITDA of $174mm and 10x of EBITDA multiple.

ACCESS TO MARKETS (2 – AVERAGE)

AMR ranks in the top half of unhedged oil differentials in 1Q18. We believe Mid-con realizations will continue to be superior to Permian in 2018 and 2019, considering the recent midstream constraints in the Permian.

Guggenheim Coverage 1Q 2018 Oil/Gas/NGL Differentials Ranking



Source: Company Filings

ASSET OVERVIEW

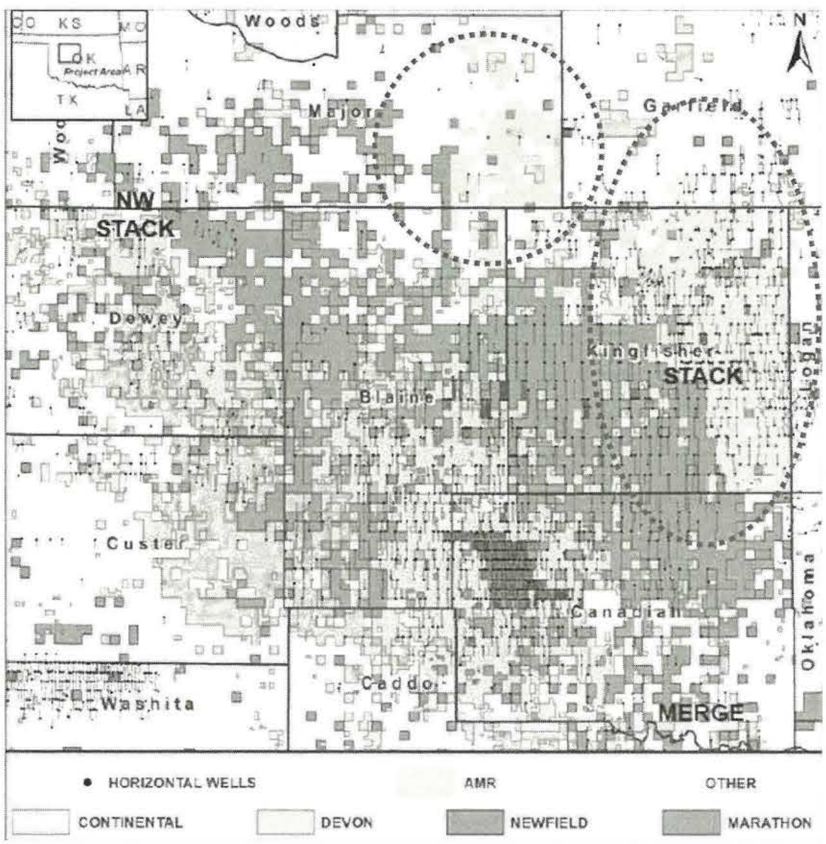
Spanning the STACK Black Oil Play

Alta Mesa Resources (NASDAQ: AMR) is a STACK oil pure player. The name STACK comes from an acronym describing both location—Sooner Trend Anadarko Basin Canadian and Kingfisher County—and the multiple, stacked productive formations present in the region. The STACK is a prolific hydrocarbon system with high oil and liquids-rich natural gas content, multiple horizontal target horizons, extensive production history and historically high drilling success rates. The STACK is among the lowest cost oil basins in the U.S. with asset quality comparable to the Permian Basin and the second most-active play in Lower 48, behind the Permian.

AMR holds ~130,000 net acres in Kingfisher, Major, Garfield and Blaine Counties, OK, of which more than 95% is held-by-production (HBP), with an average working interest of 78%. As of year-end 2017, there were 176.2 mmboe of proved reserves (30% PDP; 39% oil). The company also owns Kingfisher Midstream (KFM) with over 400 miles of gathering pipeline, 350 mmcf/d of processing capacity and 50 mbbls of crude oil storage capacity.

Production at 1Q18 was ~24.0 mboepd (53% oil, 17% NGL, 30% gas). The acreage consists of two regions: ~110,000 net acres in Kingfisher and Garfield counties, OK and ~20,000 acres in Major County, OK. The company has identified 2,075 gross operated locations and ~4,200 gross total locations in its Kingfisher County acreage. It is mostly located in the normally-pressured, up-dip oil window of the STACK play. It is offset by NFX, GST, and MRO. The Major county acreage is sparsely drilled, and the company plans to test the Osage in 2018. It is offset by CHAP, CLR, GST and MRO.

STACK Operator Acreage Map

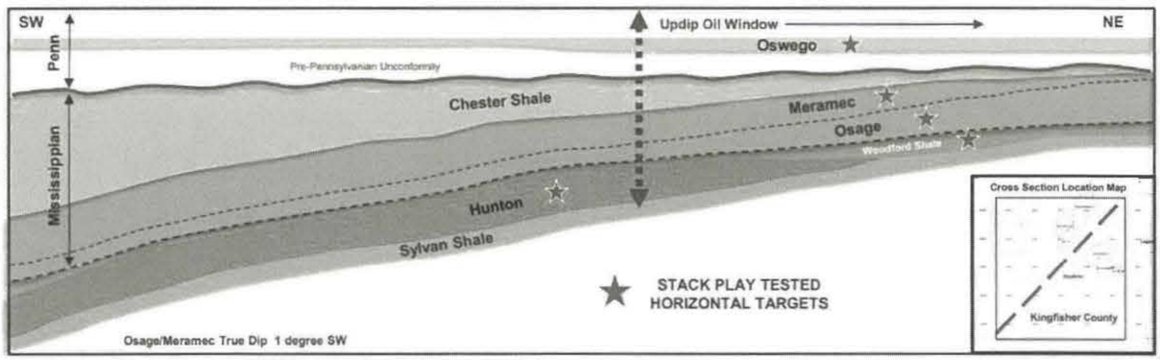


Source: Company Presentation

Kingfisher Footprint Evolved Through Two Decades of Development in the Area

The predecessor of Alta Mesa Resources, Alta Mesa Holdings LP, was established in 1987. Alta Mesa has been working in the Sooner Trend Field for over 20 years. It entered the play in the early 1990s by acquiring fields originally developed by Texaco, Exxon and Conoco. The fields have historically been shallow-decline, long-lived vertical oil wells originally drilled on 80-acre spacing and water-flooded to varying degrees. After over two decades of history in Kingfisher County, AMR has established a sizable position, with ~110,000 net acres in the area. AMR has doubled its acreage position since January 2015, most of which is held by production. Total drilling inventory is ~4,200 (gross) wells as of YE 2017, including 2,075 operated locations. AMR estimates that it could add another ~8,000 possible gross locations through down-spacing and testing of additional zones. The Kingfisher acreage is ~99% HBP with net revenue interest (NRI) of ~65%. Since late 2012, AMR has focused on the horizontal development of the Osage, Meramec, Woodford, and Oswego formations. Generally speaking, the formations are made up of highly naturally fractured reservoir and geologic systems with an Osage/Meramec system up to 500' thick with no frac or flow barriers. AMR believes this acreage is also prospective for Big Lime, Prue, Skinner, Red Fork, Cherokee Shale, Manning Lime, and Hunton Lime formations. AMR has developed for more than 300 horizontal STACK wells, mostly in the Osage formation, across the entirety of its Kingfisher acreage, which ranks AMR as one of the top producers in the STACK.

Simplified Stratigraphy of Major STACK Targets in Kingfisher County



Source: Company Presentation

Major County Bolt-on Acquisition Provides Additional Upside Potential

In July 2017, the company acquired ~20,000 net acres in Major and Blaine Counties, with an average working interest of ~78%. The acreage is located in the up-dip oil window of the STACK play, offsetting GST, CHAP, NFX and JCO. This area is sparsely drilled by the industry, with increasing activities in 2018. Offset operators are currently producing from: Osage, Meramec, Oswego and Woodford formations. This transaction boosted AMR's land base by 18%, and drilling inventory by ~872 primary locations (19%). AMR is currently drilling its first batch of wells in the area. Results are expected to be released in late 2018/early 2019.

MANAGEMENT TEAM

Name	Title	Bio
James Hackett	Executive Chairman and Chief Operating Officer of Midstream	Mr. Hackett has served as the Executive Chairman and Chief Operating Officer of Midstream since the closing of the Business Combination in February 2018. Prior to that, Mr. Hackett served as the Chief Executive Officer and Director from March 2017 to February 2018. Mr. Hackett serves as a partner at Riverstone and as a Director in Silver Run II. Prior to this, Mr. Hackett served as the Executive Chairman and Chief Executive Officer of Anadarko Petroleum Corporation from 2006 to 2013 and 2003 to 2012, respectively. Prior to that, Mr. Hackett served as the President and Chief Executive Officer of Devon Energy Corporation, post its merger with Ocean Energy where he served as the Chairman, President, and Chief Executive Officer. Previously, Mr. Hackett has also served in senior positions with Seagull, Duke Energy, and Pan Energy. Mr. Hackett has also held several positions in engineering, finance and marketing divisions of various sectors in the oil and gas industry including midstream, oil field services and power. Mr. Hackett also serves as a Director of Enterprise Products Holdings, Fluor Corporation, National Oilwell Varco, Sierra Oil and Gas and Talen Energy Corporation and Crimson Resources. Mr. Hackett is also a former Chairman of the Board of the Federal Reserve Bank of Dallas. Mr. Hackett holds a Bachelor of Science degree from the University of Illinois and an MBA and MTS from Harvard University.
Hal Chappelle	President and Chief Executive Officer	Mr. Chappelle has served as the President and Chief Executive Officer since the closing of the Business Combination in February 2018. Prior to that, Mr. Chappelle served as the President, Chief Executive Officer and Director of Alta Mesa since his joining in November 2004. Mr. Chappelle has oil and gas industry experience of more than 30 years in field operations, engineering, management, marketing and trading, acquisitions and divestitures and field re-development in collaboration with majors including Exxon and Chevron. Mr. Chappelle built a strong management and technical team to develop Alta Mesa as a premium Stack Operator. Previously, Mr. Chappelle also served at Louisiana Land & Exploration Company, Burlington Resources, Southern Company and Mirant. Mr. Chappelle is a retired Commander from the U.S. Navy Reserve. Mr. Chappelle holds a Bachelor of Chemical Engineering from Auburn University and a Master of Science in Petroleum Engineering from The University of Texas at Austin.
Michael McCabe	Vice President and Chief Financial Officer	Mr. McCabe has served as the Chief Financial Officer since the closing of the Business Combination in February 2018. Prior to that, Mr. McCabe served as the Chief Financial Officer and Vice President of Alta Mesa since his joining in 2006. Mr. McCabe has corporate finance experience of more than 25 years, with a focus on energy industry. Previously, Mr. McCabe has also served as the President and Sole Owner of a private consulting firm, Bridge Management Group. Mr. McCabe has also held several senior level positions with Bank of Tokyo, Bank of New England, and Key Bank. Mr. McCabe holds a Bachelor of Science in Chemistry and Physics from Bridgewater State University, a Master of Science in Chemical Engineering from Purdue University and a Master of Business Administration in Financial Management from Pace University.
Mike Ellis	Director and Chief Operating Officer - Upstream	Mr. Ellis has served as the Director and Chief Operating Officer of Upstream since the closing of the Business Combination in February 2018. Prior to that, Mr. Ellis served as Chairman, Chief Operating Officer and Vice President of Engineering at Alta Mesa. Mr. Ellis founded Alta Mesa in 1987 after starting his professional career with Amoco and managed all day-to-day engineering and field operations for Alta Mesa. Mr. Ellis started with small exploitation projects and grew the asset base successfully with consecutive acquisitions of fields from major oil companies and with consistent success in exploration and development drilling. Mr. Ellis has more than 30 years of experience in management, engineering, exploration and acquisitions and divestitures. Mr. Ellis holds a Bachelor of Science in Civil Engineering from West Virginia University.
Gene Cole	Vice President, Chief Technical Officer	Mr. Cole has served as a Vice President, Chief Technical Officer and Director since August 2015. Mr. Cole joined Alta Mesa in 2007. Mr. Cole has domestic and international oilfield experience of over 25 years' in well completion, well stimulation design and execution. Mr. Cole began his carrier at Dowell Schlumberger as a Field Engineer and has held several responsible positions from 1986 to 2007 in the areas of field operations, engineering and management. Mr. Cole holds a Bachelor of Science in Petroleum Engineering from Marietta College in Ohio.
Kevin Bourque	Vice President of Operations	Mr. Bourque has served as Vice President of Mid-Continent Operations since 2012. Mr. Bourque joined Alta Mesa in 2007 as a field engineer and moved into his current role when Alta Mesa started the STACK horizontal drilling program. Mr. Bourque has over 20 years of experience with more than 10 years of E&P operational experience with Alta Mesa and more than 10 years of project management and business management experience as owner of his own company. Mr. Bourque drove the growth of Alta Mesa's mid-continent drilling and production operations.
Tim Turner	Vice President of Corporate Development	Mr. Turner has served as Vice President of Corporate Development since 2013. Mr. Turner has industry experience of more than 30 years including reservoir engineering, various operations and managerial roles with Sun Oil, Santa Fe Minerals, Fina Oil & Chemical, Total, Newfield Exploration and Quantum Resources. Mr. Turner has also managed corporate reserves and led A&D, business development, asset and new ventures teams. Mr. Turner holds a Bachelor of Science in Petroleum Engineering from the University of Texas and an MBA in Finance from Oklahoma City University.
David McClure	Vice President, Facilities and Midstream	Mr. McClure has served as the Vice President of Facilities and Midstream operations since 2016. Prior to that, Mr. McClure served as Vice President for Louisiana Operations and led a team of engineers, regulatory, land, geoscience, and operations experts for Weeks Island field development from 2010 to 2016. Mr. McClure has experience in onshore and offshore operations and facilities engineering of more than 15 years. Mr. McClure began his professional career with ExxonMobil and advanced his career in positions with increasing responsibility in offshore, subsea, and pipeline engineering, operations, and management. Previously, Mr. McClure has also served as a consultant at Tetra Technologies on various deep-water projects. Mr. McClure holds a Bachelor of Science in Chemical Engineering from Auburn University.
David Murrell	VP, Land and Business Development	Mr. Murrell has served as Vice President of Land and Business Development since 2006. Mr. Murrell has more than 30 years of experience in Gulf Coast leasing, exploration and development programs, contract management and acquisitions and divestitures. Mr. Murrell creation of a structured land management system along with a team of lease analysts, landsmen, and field representatives has facilitated Alta Mesa's growth. Mr. Murrell holds a Bachelor of Business Administration in Petroleum Land Management from the University of Oklahoma.

Source: Company filings

Board Composition

The company has 11 Directors. The composition is as follows:

- 3 from Alta Mesa (Hackett, Chappelle, Ellis)
- 2 from Riverstone (Lapeyre, Leuschen)
- 1 from Bayou City (McMullen)
- 1 from HPS Investment (Dimitrievich)
- 4 "Independent" (Gutermuth, Walters, Tepper, Sinclair)

Name	Title	Age	Affiliation	Bio
James Hackett	Executive Chairman of the Board and COO - Midstream	64	Riverstone	Mr Hackett has served as the Executive Chairman and Chief Operating Officer of Midstream since March 2017
Hal Chappelle	Director and CEO	61		Mr. Chappelle has served as the President, CEO and Director of Alta Mesa since its joining in November 2004.
Michael E. Ellis	Director and COO - Upstream	61		Mr Ellis founded Alta Mesa in 1987 and serves as Chief Operating Officer and Director of Alta Mesa.
David M. Leuschen	Director	66	Riverstone	Mr. Leuschen is a Co- Founder and Senior Managing Director of Riverstone. Prior to founding Riverstone in 2000, Mr. Leuschen served as a Partner and Managing Director at Goldman Sachs. Mr. Leuschen also serves as a nonexecutive member of the board at Riverstone Energy Limited and Centennial Resource Development, Inc. since May 2013 and Oct. 2016, respectively. Mr. Leuschen also serves on the boards or equivalent bodies of a number of Riverstone portfolio companies and their affiliates. Mr. Leuschen holds an MBA and an A.B. degree from Dartmouth College.
Pierre F. Lapeyre Jr	Director	55	Riverstone	Mr. Lapeyre is a Co- Founder and Senior Managing Director of Riverstone. Prior to founding Riverstone in 2000 Mr. Lapeyre served as a Managing Director of Goldman Sachs. Mr. Lapeyre also serves as a nonexecutive member of the board at Riverstone Energy Limited and Centennial Resource Development, Inc. since May 2013 and Oct. 2016, respectively. Mr. Lapeyre also serves on the boards or equivalent bodies of a number of Riverstone portfolio companies and their affiliates. Mr. Lapeyre holds an MBA from the University of North Carolina and a B.S. from the University of Kentucky
William W. McMullen	Director	32		Mr. McMullen is the Founder and Managing Partner of Houston based oil and gas private equity firm, Bayou City Energy. Prior to founding BCE in 2015, Mr. McMullen founded Bayou City Energy Partners in 2014, a private equity vehicle focused on investments in the oil and gas sector. Previously, Mr. McMullen served as VP at White Deer Energy. Mr. McMullen holds Bachelor's degree from Harvard University.
Don Dimitrievich	Director	46		Mr. Dimitrievich currently serves as a Managing Director at HPS and oversees direct credit investment strategy in the energy and power sectors. Prior to HPS, Mr. Dimitrievich also served at Citi Credit Opportunities as a Managing Director. Mr. Dimitrievich has also served as corporate attorney at Skadden, Arps, Slate, Meagher & Flom LLP from 1996 to 2004. Mr. Dimitrievich also serves as a Director for Blue Ridge Mountain Resources, Inc., Expro International Group Holdings Ltd., Glacier Oil & Gas Corp., Marquis Resources, LLC and Upstream Exploration LLC. Mr. Dimitrievich holds a law degree from McGill University and a chemical engineering degree from Queen's University
William D. Gutermuth	Director	68		Mr. Gutermuth is the Founder and Chairman of Bluegrass Capital LLC, an investment and consulting firm. Prior to founding Bluegrass, Mr. Gutermuth practiced corporate and transactional law for 35 years at Bracewell and served as an equity partner at Bracewell & Giuliani LLP and its predecessor firm, Bracewell & Patterson, LLP. From 2007 to 2012 Mr. Gutermuth served as the director of Main Street Capital Corporation and on the Compensation and Nominating and Governance Committees during his tenure as a director. Mr. Gutermuth served as a Director of Silver Run Acquisition Corporation from November 2015 until its acquisition by
Jeffrey H. Tepper	Director	51		Mr. Tepper founded JHT Advisors LLC, an M&A advisory and investment firm. Mr. Tepper also served as Director of Silver Run Acquisition Corporation from November 2015 until its acquisition by Centennial Resource Production, LLC in October 2016.Following the acquisition, Mr Tepper has continued to serve as Director in Centennial Resource Development, Inc. since October 2016. From 1990 to 2013, Mr. Tepper held variety of senior management and operating roles at the Gleacher & Company, Inc. and its predecessors and affiliates. Prior to Gleacher, Mr. Tepper served at Morgan Stanley & Co from 1987 to 1990 as financial analyst in the M&A and merchant banking division. Mr. Tepper holds MBA from Columbia Business School and a B.S. from the University of Pennsylvania.
Diana J. Walters	Director	54		Ms. Walters has experience in the natural resources sector of more then 30 years. Ms. Walters since 2014 has been providing advisory services in natural resources sector as the owner of 575 Grant, LLC. Prior to that, she served as the President and CEO of Liberty Metals & Mining Holdings, LLC and senior management member for Liberty Mutual Asset Management from 2010 to 2014. Prior to Liberty, Ms Walters served as Managing Partner of a natural resource advisory firm Eland Capital, LLC from 2007 to 2010. Ms. Walters has also served as CFO of Tatham Offshore Inc. Ms. Walter has also served as a Director of Silver Run Acquisition Corp. from Nov. 2015 until the completion of Centennial acquisition in Oct. 2016. Ms. Walter currently serves on the board of directors of Platinum Group Metals and Electrum Special Acquisition Corporation. Ms. Walters holds an M.A. and B.A. from the University of Texas.
Donald R. Sinclair	Director	60		Mr Sinclair has served as the Director since closing of the Business Combination in February 2018. Mr Sinclair has worked in the oil and gas industry for over 30 years with focus in marketing and trading and midstream sector. Mr Sinclair currently serves as the Chairman and President of WTX Pumping Services LLC. Mr Sinclair also serves as senior advisor to Anadarko Petroleum Corporation, senior advisor to Western Gas Equity Holdings, LLC and as general partner of Western Gas Equity Partners LP. Prior to that, Mr. Sinclair served as the President, CEO and Director of WES GP from 2009 to 2017. Mr Sinclair holds Bachelor of Business Administration degree from Texas Tech University.

Source: Company filings

VALUATION

Summary of Regional Acquisition & Divestiture Activities

Assets in the STACK have traded frequently over the last three years, with 2017 being the most active year. DVN's acquisition of Felix Energy in 2015 and SRUN's acquisition of Alta Mesa in 2017, are the highest value transactions on a dollar per net acre basis. Below we have included recent A&D in the STACK region.

Major Mid-Con A&D Transactions

Seller	Alta Mesa	Staghorn	Felix	PayRock	CHK	Average
Purchaser	SRUN	Chisholm	DVN	MRO	NFX	
Date	8/16/2017	3/29/2017	12/7/2015	6/20/2016	5/5/2016	
Purchase Price ($mm)	$3,800*	$ 613	$ 1,900	$ 888	$ 470	
Net Acres	120,000	41,386	80,000	61,000	42,000	
Production (MBoe/d)	20.0	2.8	9.0	5.6	3.8	
$/Acre Not Adjusted for Production	$ 20,833	$ 14,800	$ 23,700	$ 14,600	$ 11,200	$17,000
$/Acre Adjusted for Production	$ 16,500	$ 13,000	$ 21,000	$ 11,000	$ 9,000	$14,000

Source: Company Filings, Shaleexperts.com, Guggenheim Securities, LLC Estimates
**Purchase price includes Kingfisher Midstream.*

Price Target / NAV Estimate

Our $10.00 PT/NAV estimate for AMR is based on our 2020 estimate of proved reserves (net of debt) and midstream value. Proved reserves (net of debt) represent two-third of our NAV estimate, or $6.50 per share, while the balance is midstream value. Based on our forecast for AMR's development activities, we estimate the company's proved reserve will grow by ~176% at YE20 from YE17 level, to 2.9 tcfe. Proved reserves are valued at $1.18 per mcfe or ~$3.4bn, less ~$490mm of net debt. We assume $2.75 / $60 gas / oil prices in 2020 for NAV estimate. Our valuation for Kingfisher Midstream of $1.7bn, is based on our estimate of 2020 midstream EBITDA of $174mm and 10x of EBITDA multiple. If we back out $1.7bn of midstream value from AMR's ~ $3.0bn enterprise value, upstream reserves are trading at $1.5bn, which is just a 50% premium to 2017 pv10 based on $51 oil. We estimate 2018 pv10 could near $2.0bn based on $60 oil and high growth rates.

INVESTMENT RISKS

Delineation / Inventory Risk. The company's STACK play properties remain largely undeveloped and are in the very early innings of delineation. A lack of consistent results across the footprint could discredit the potential "probable" reserve inventory. New development and exploration wells in the STACK play may not produce hydrocarbons, may underperform expectations, or may not be commercially viable.

Execution Risk. Drilling and completion risks exist, particularly as the company continues to push the envelope on "Gen 2.5" type wells and beyond. These risks include landing/staying in zone, effectively stimulating the planned stages and the potential for diminishing returns beyond a certain level of proppant/fluid intensity.

Shareholder Risk. Riverstone Holdings LLC, currently owns an approximately 22% stake in the company. Liquidation events from Riverstone could cause short-term price fluctuations on common stock shares. As long as Riverstone controls a significant percentage of voting power, they will have the ability to strongly influence all corporate actions which require stockholder approval, and their interests may conflict with the interests of AMR's other stockholders.

General E&P Industry Risks. A prolonged period of lower oil and gas prices can be detrimental to growth and asset values. The inability to fund development due to weak capital markets can also reduce growth rates. The regulation or prohibition of fracking on state and federal lands can reduce resource potential. Regulation of product transport on pipe and rail can add to costs, reduce realizations, and interrupt sales. In some areas, the Endangered Species Act can curtail drilling activity if native species come under protection.

Alta Mesa Resources Inc. (AMR)
Consolidated Statement of Operations
Guggenheim Securities, LLC

(data in thousands, except as indicated)	FY17	FY18E	FY19E	FY20E	1Q18	2Q18E	3Q18E	4Q18E	1Q19E	2Q19E	3Q19E	4Q19E
Revenues												
Natural gas	$ 318,828	$ 62,549	$ 113,022	$ 168,266	$ 9,486	$ 13,684	$ 17,351	$ 22,028	$ 25,352	$ 24,931	$ 28,849	$ 33,889
Oil	$ -	$ 403,520	$ 797,456	$ 1,179,523	$ 71,250	$ 89,870	$ 110,567	$ 131,834	$ 161,817	$ 187,211	$ 212,461	$ 235,967
NGL	$ -	$ 49,389	$ 83,411	$ 124,692	$ 8,714	$ 11,360	$ 14,065	$ 15,250	$ 16,893	$ 19,544	$ 22,180	$ 24,793
Midstream Net	$ (50,711)	$ 98,761	$ 151,885	$ 174,177	$ 17,320	$ 23,269	$ 26,371	$ 31,801	$ 34,613	$ 36,448	$ 39,355	$ 41,468
Cash Derivatives	$ 4,117	$ 6,271	$ -	$ -	$ 6,271	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other	$ 7,420	$ 7,422	$ -	$ -	$ 7,422	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Revenues	$ 279,654	$ 627,912	$ 1,145,774	$ 1,646,659	$ 120,463	$ 138,182	$ 168,354	$ 200,912	$ 238,676	$ 268,134	$ 302,846	$ 336,117
Expenses												
LOE	$ 48,207	$ 81,041	$ 141,131	$ 209,095	$ 14,470	$ 18,809	$ 22,466	$ 25,296	$ 28,629	$ 33,122	$ 37,589	$ 41,790
Production taxes	$ 6,935	$ 11,314	$ 20,872	$ 30,922	$ 2,368	$ 2,413	$ 2,982	$ 3,551	$ 4,285	$ 4,865	$ 5,533	$ 6,188
GP&T and other operating	$ 5,014	$ 27,458	$ 49,396	$ 73,183	$ 4,746	$ 6,156	$ 7,703	$ 8,854	$ 10,020	$ 11,593	$ 13,156	$ 14,627
G&A	$ 63,268	$ 78,409	$ 35,000	$ 36,000	$ 58,909	$ 6,500	$ 6,500	$ 6,500	$ 8,500	$ 8,500	$ 9,000	$ 9,000
DD&A	$ 282,309	$ 154,944	$ 282,262	$ 418,191	$ 27,361	$ 34,198	$ 42,793	$ 50,592	$ 57,259	$ 66,244	$ 75,179	$ 83,580
Derivative (gain)/loss	$ (4,170)	$ 21,619	$ -	$ -	$ 21,519	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Exploration	$ 13,563	$ 27,588	$ 26,000	$ 26,000	$ 8,588	$ 7,000	$ 6,000	$ 6,000	$ 6,500	$ 6,500	$ 6,500	$ 6,500
Other	$ 1,676	$ 141	$ -	$ -	$ 141	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest expense	$ 50,861	$ 48,545	$ 50,120	$ 50,000	$ 10,955	$ 12,530	$ 12,530	$ 12,530	$ 12,530	$ 12,530	$ 12,530	$ 12,530
Interest (income)	$ -	$ (718)	$ -	$ -	$ (718)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Expenses	$ 467,663	$ 450,342	$ 604,780	$ 843,392	$ 148,439	$ 87,606	$ 100,974	$ 113,323	$ 127,724	$ 143,354	$ 159,488	$ 174,214
Pretax income	**$ (188,009)**	**$ 177,570**	**$ 540,993**	**$ 803,267**	**$ (27,976)**	**$ 50,576**	**$ 67,380**	**$ 87,590**	**$ 110,953**	**$ 124,780**	**$ 143,358**	**$ 161,903**
Income tax expense (benefit)	$ (30,849)	$ 47,574	$ 135,248	$ 200,817	$ (3,813)	$ 12,644	$ 16,845	$ 21,897	$ 27,738	$ 31,195	$ 35,839	$ 40,476
Net Income (loss)	**$ (157,160)**	**$ 129,997**	**$ 405,745**	**$ 602,450**	**$ (24,163)**	**$ 37,932**	**$ 50,535**	**$ 65,692**	**$ 83,215**	**$ 93,585**	**$ 107,518**	**$ 121,427**
Income (loss) from Disc Ops	$ -	$ (7,593)	$ -	$ -	$ (7,593)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Preferred stock dividends	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income to noncontrolling interests	$ (87,619)	$ (20,314)	$ -	$ -	$ (20,314)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Nonrecurring gain (charges)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NET INCOME (LOSS) - TO COMMON	**$ (157,160)**	**$ 150,311**	**$ 405,745**	**$ 602,450**	**$ (3,849)**	**$ 37,932**	**$ 50,535**	**$ 65,692**	**$ 83,215**	**$ 93,585**	**$ 107,518**	**$ 121,427**
EPS, excl. non-recurring (basic)	**$ (0.41)**	**$ 0.39**	**$ 1.06**	**$ 1.57**	**$ (0.01)**	**$ 0.10**	**$ 0.13**	**$ 0.17**	**$ 0.22**	**$ 0.24**	**$ 0.28**	**$ 0.32**
EPS, excl. non-recurring (diluted)	**$ (0.40)**	**$ 0.38**	**$ 1.04**	**$ 1.54**	**$ (0.01)**	**$ 0.10**	**$ 0.13**	**$ 0.17**	**$ 0.21**	**$ 0.24**	**$ 0.28**	**$ 0.31**
Shares Outstanding (basic)	382,772	383,943	384,334	384,334	382,772	384,334	384,334	384,334	384,334	384,334	384,334	384,334
Shares Outstanding (diluted)	388,872	390,043	390,434	390,434	388,872	390,434	390,434	390,434	390,434	390,434	390,434	390,434

CASH FLOW:	FY17	FY18E	FY19E	FY20E	1Q18	2Q18E	3Q18E	4Q18E	1Q19E	2Q19E	3Q19E	4Q19E
EBITDAX	$ 156,230	$ 433,190	$ 899,375	$ 1,297,458	$ 43,470	$ 104,305	$ 128,704	$ 156,711	$ 187,241	$ 210,054	$ 237,567	$ 264,513
Cash Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest	$ 60,884	$ 48,545	$ 50,120	$ 50,000	$ 10,955	$ 12,530	$ 12,530	$ 12,530	$ 12,530	$ 12,530	$ 12,530	$ 12,530
CFFO	$ 95,346	$ 384,645	$ 849,255	$ 1,247,458	$ 32,515	$ 91,775	$ 116,174	$ 144,181	$ 174,711	$ 197,524	$ 225,037	$ 251,983
Cash flow per share	**$ 0.25**	**$ 0.99**	**$ 2.18**	**$ 3.20**	**$ 0.08**	**$ 0.24**	**$ 0.30**	**$ 0.37**	**$ 0.45**	**$ 0.51**	**$ 0.58**	**$ 0.65**

Source: Company Reports, Guggenheim Securities, LLC estimates

 See pages 43 - 44 for analyst certification and important disclosures.

Alta Mesa Resources Inc. (AMR)
Consolidated Statement of Operations
Guggenheim Securities, LLC

PRODUCTION:	FY17	FY18E	FY19E	FY20E	1Q18	2Q18E	3Q18E	4Q18E	1Q19E	2Q19E	3Q19E	4Q19E
Oil production (mbbls)	3,907	6,780	12,914	19,102	1,145	1,510	1,890	2,234	2,621	3,032	3,441	3,821
NGL production (mbbls)	1,277	2,108	3,666	5,481	374	479	585	670	743	859	975	1,090
Gas production(Mmcf)	13,973	23,435	41,647	61,600	3,857	5,164	6,547	7,867	8,451	9,777	11,096	12,323
Production (Mmcfe)	**45,077**	**76,763**	**141,131**	**209,095**	**12,971**	**17,099**	**21,397**	**25,296**	**28,629**	**33,122**	**37,589**	**41,790**
Mmboe	*7,513*	*12,794*	*23,522*	*34,849*	*2,162*	*2,850*	*3,566*	*4,216*	*4,772*	*5,520*	*6,265*	*6,965*
Daily oil production (mb/d)	10.7	18.6	35.4	52.2	12.7	16.6	20.5	24.3	29.1	33.3	37.4	41.5
Daily NGL production (mb/d)	3.5	5.8	10.0	15.0	4.2	5.3	6.4	7.3	8.3	9.4	10.6	11.8
Daily gas production (mmcf/d)	38.3	64.2	114.1	168.3	42.9	56.7	71.2	85.5	93.9	107.4	120.6	133.9
Daily equiv. production (Mmcfe)	**123.5**	**210.3**	**386.7**	**571.3**	**144.1**	**187.9**	**232.6**	**275.0**	**319.4**	**365.4**	**410.2**	**455.6**
Daily equiv. production (mboe)	20.6	35.1	64.4	95.2	24.0	31.3	38.8	45.8	53.2	60.9	68.4	75.9
Q-O-Q Production Growth					*8%*	*30%*	*24%*	*18%*	*16%*	*14%*	*12%*	*11%*
Y-O-Y Production Growth	*58%*	*70%*	*84%*	*48%*	*24%*	*53%*	*90%*	*106%*	*122%*	*94%*	*76%*	*66%*
% oil	*52%*	*53%*	*55%*	*55%*	*53%*	*53%*	*53%*	*53%*	*55%*	*55%*	*55%*	*55%*
% NGL	*17%*	*16%*	*16%*	*16%*	*17%*	*17%*	*16%*	*16%*	*16%*	*16%*	*16%*	*16%*
% gas	*31%*	*31%*	*30%*	*29%*	*30%*	*30%*	*31%*	*31%*	*29%*	*29%*	*29%*	*29%*
WTI oil price	$ 50.82	$ 65.17	$ 65.00	$ 65.00	$ 62.91	$ 67.79	$ 65.00	$ 65.00	$ 65.00	$ 65.00	$ 65.00	$ 65.00
Mt Belvieu price	$ 21.62	$ 26.07	$ 26.00	$ 26.00	$ 25.16	$ 27.12	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00	$ 26.00
Henry Hub gas price	$ 3.09	$ 2.92	$ 2.95	$ 2.95	$ 3.08	$ 2.82	$ 2.80	$ 3.00	$ 3.25	$ 2.75	$ 2.80	$ 3.00
Oil price realized	$ 49.13	$ 57.98	$ 61.75	$ 61.75	$ 54.92	$ 59.50	$ 58.50	$ 59.00	$ 61.75	$ 61.75	$ 61.75	$ 61.75
NGL price realized	$ 23.31	$ 23.46	$ 22.75	$ 22.75	$ 23.30	$ 23.73	$ 24.05	$ 22.75	$ 22.75	$ 22.75	$ 22.75	$ 22.75
Gas price realized	$ 3.01	$ 2.77	$ 2.73	$ 2.74	$ 2.96	$ 2.65	$ 2.65	$ 2.80	$ 3.00	$ 2.55	$ 2.60	$ 2.75
Gas Equivalent ($/mcf)	**$ 5.85**	**$ 6.61**	**$ 7.05**	**$ 7.04**	**$ 6.40**	**$ 6.72**	**$ 6.64**	**$ 6.69**	**$ 7.13**	**$ 6.99**	**$ 7.01**	**$ 7.05**
Oil Premium/ Discount	*$ (1.69)*	*$ (7.19)*	*$ (3.25)*	*$ (3.25)*	*$ (7.99)*	*$ (8.29)*	*$ (6.50)*	*$ (6.00)*	*$ (3.25)*	*$ (3.25)*	*$ (3.25)*	*$ (3.25)*
NGL Premium/ Discount	*$ 1.69*	*$ (2.61)*	*$ (3.25)*	*$ (3.25)*	*$ (1.86)*	*$ (3.39)*	*$ (1.95)*	*$ (3.25)*	*$ (3.25)*	*$ (3.25)*	*$ (3.25)*	*$ (3.25)*
Gas Premium/ Discount	*$ (0.08)*	*$ (0.16)*	*$ (0.23)*	*$ (0.21)*	*$ (0.12)*	*$ (0.17)*	*$ (0.15)*	*$ (0.20)*	*$ (0.25)*	*$ (0.20)*	*$ (0.20)*	*$ (0.25)*

MARGINS PER MCFE	FY17	FY18E	FY19E	FY20E	1Q18	2Q18E	3Q18E	4Q18E	1Q19E	2Q19E	3Q19E	4Q19E
Revenue	$ 7.16	$ 6.80	$ 7.04	$ 7.04	$ 6.40	$ 6.72	$ 6.64	$ 6.69	$ 7.13	$ 6.99	$ 7.01	$ 7.05
LOE	$ 0.98	$ 1.06	$ 1.00	$ 1.00	$ 1.12	$ 1.10	$ 1.05	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00
GP&T	$ 0.65	$ 0.36	$ 0.35	$ 0.35	$ 0.37	$ 0.36	$ 0.36	$ 0.35	$ 0.35	$ 0.35	$ 0.35	$ 0.35
Production Tax	$ 0.12	$ 0.15	$ 0.15	$ 0.15	$ 0.18	$ 0.14	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.15	$ 0.15
G&A	$ 1.40	$ 1.02	$ 0.25	$ 0.17	$ 4.54	$ 0.70	$ 0.70	$ 0.70	$ 0.30	$ 0.26	$ 0.24	$ 0.22
Int Exp	$ 1.35	$ 0.63	$ 0.36	$ 0.24	$ 0.84	$ 0.73	$ 0.59	$ 0.50	$ 0.44	$ 0.38	$ 0.33	$ 0.30
Income tax rate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cash flow	**$ 4.01**	**$ 4.21**	**$ 5.30**	**$ 5.37**	**$ (0.65)**	**$ 3.69**	**$ 3.80**	**$ 4.00**	**$ 4.89**	**$ 4.86**	**$ 4.94**	**$ 5.04**
DD&A	$ 6.26	$ 2.02	$ 2.00	$ 2.00	$ 2.11	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00	$ 2.00
Earnings	**$ (2.25)**	**$ 2.20**	**$ 3.30**	**$ 3.37**	**$ (2.76)**	**$ 1.69**	**$ 1.80**	**$ 2.00**	**$ 2.89**	**$ 2.86**	**$ 2.94**	**$ 3.04**
Income tax rate	*16%*	*27%*	*25%*	*25%*	*14%*	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*
% deferred	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
EBITDA Margins	*56%*	*69%*	*78%*	*79%*	*36%*	*75%*	*76%*	*78%*	*78%*	*78%*	*78%*	*79%*

Source: Company Reports, Guggenheim Securities, LLC estimates

See pages 43 - 44 for analyst certification and important disclosures.

Alta Mesa Resources Inc. (AMR)
Consolidated Statement of Operations
Guggenheim Securities, LLC

CASH FLOW ANALYSIS	FY17	FY18E	FY19E	FY20E
Sources				
Operating Cash Flow	$ 95,346	$ 384,645	$ 849,255	$ 1,247,458
Working Capital	(33,000)	(155,000)	12,000	(15,000)
Asset Sales	25,205	-	-	-
Net Financing - Debt	76,443	(28,065)	68,000	(200,000)
- Equity	207,875	400,000	-	-
Other		1,042,742	-	-
TOTAL	**$ 371,869**	**$ 1,644,322**	**$ 929,255**	**$ 1,032,458**
Uses				
CAPEX	$ 313,961	$ 785,136	$ 927,105	$ 1,030,300
Dividends	-	-	-	-
Asset Purchases	55,605	796,826	-	-
Other	1,913	39,333	-	-
TOTAL	**$ 371,479**	**$ 1,621,296**	**$ 927,105**	**$ 1,030,300**
Excess / <deficiency>	**$ 390**	**$ 23,026**	**$ 2,150**	**$ 2,158**

CASH FLOW ANALYSIS	1Q18	2Q18E	3Q18E	4Q18E	1Q19E	2Q19E	3Q19E	4Q19E
Sources								
Operating Cash Flow	$ 32,515	$ 91,775	$ 116,174	$ 144,181	$ 174,711	$ 197,524	$ 225,037	$ 251,983
Working Capital	$ (339,000)	$ 91,000	$ 76,000	$ 17,000	$ 12,000	$ -	$ -	$ -
Asset Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Financing - Debt	$ (108,065)	$ -	$ -	$ 80,000	$ 41,000	$ 34,000	$ 10,000	$ (17,000)
- Equity	$ 400,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other	$ 1,042,742	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	**$ 1,028,192**	**$ 182,776**	**$ 192,174**	**$ 241,181**	**$ 227,711**	**$ 231,524**	**$ 235,037**	**$ 234,983**
Uses								
CAPEX	$ 171,151	$ 182,185	$ 191,436	$ 240,364	$ 227,091	$ 230,822	$ 234,596	$ 234,596
Dividends	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Asset Purchases	$ 796,826	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other	$ 39,333	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	**$ 1,007,310**	**$ 182,185**	**$ 191,436**	**$ 240,364**	**$ 227,091**	**$ 230,822**	**$ 234,596**	**$ 234,596**
Excess / <deficiency>	**$ 20,882**	**$ 589**	**$ 737**	**$ 818**	**$ 620**	**$ 702**	**$ 440**	**$ 387**

BALANCE SHEET ($,000)	FY17	FY18E	FY19E	FY20E
Cash	*$ 541,511*	*$ -*	*$ -*	*$ -*
Working Capital	433,040	12,239	239	15,239
Asset Retirement Obligations	10,400	6,033	6,033	6,033
Other	36,415	4,850	4,850	4,850
Credit Facility $400 million BB	-	132,000	200,000	-
Long-Term Debt	718,315	500,000	500,000	500,000
Total Debt	332,090	630,644	710,644	495,644
Equity	3,558,264	3,574,058	3,979,803	4,582,253
Total Capital	**$ 3,890,354**	**$ 4,204,702**	**$ 4,690,447**	**$ 5,077,897**
Net Debt / EBITDA	1.8X	1.4X	0.8X	0.4X
EBITDA / Cash Int Exp (x)	2.6X	8.9X	17.9X	25.9X
[illegible]	$ 9.15	$ 9.16	$ 10.19	$ 11.74

BALANCE SHEET ($,000)	1Q18	2Q18E	3Q18E	4Q18E	1Q19E	2Q19E	3Q19E	4Q19E
Cash	*$ 261,063*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*	*$ -*
Working Capital	$ 196,239	$ 105,239	$ 29,239	$ 12,239	$ 239	$ 239	$ 239	$ 239
Asset Retirement Obligations	$ 6,033	$ 6,033	$ 6,033	$ 6,033	$ 6,033	$ 6,033	$ 6,033	$ 6,033
Other	$ 4,850	$ 4,850	$ 4,850	$ 4,850	$ 4,850	$ 4,850	$ 4,850	$ 4,850
Credit Facility $400 million BB	$ 52,000	$ 52,000	$ 52,000	$ 132,000	$ 173,000	$ 207,000	$ 217,000	$ 200,000
Long-Term Debt	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Total Debt	$ 366,644	$ 457,644	$ 533,644	$ 630,644	$ 683,644	$ 717,644	$ 727,644	$ 710,644
Equity	$ 3,419,898	$ 3,457,830	$ 3,508,366	$ 3,574,058	$ 3,657,272	$ 3,750,857	$ 3,858,376	$ 3,979,803
Total Capital	**$ 3,786,542**	**$ 3,915,474**	**$ 4,042,010**	**$ 4,204,702**	**$ 4,340,916**	**$ 4,468,501**	**$ 4,586,020**	**$ 4,690,447**
Net Debt / EBITDA	2.0X	1.3X	1.3X	1.4X	1.2X	1.0X	0.9X	0.8X
EBITDA / Cash Int Exp (x)	4.0X	8.3X	10.3X	12.5X	14.9X	16.8X	19.0X	21.1X
[illegible]	$ 8.79	$ 8.86	$ 8.99	$ 9.15	$ 9.37	$ 9.61	$ 9.88	$ 10.19

Source: Company Reports, Guggenheim Securities, LLC estimates

See pages 43 - 44 for analyst certification and important disclosures.

Alta Mesa Resources Inc. (AMR)
NAV Forecast
Guggenheim Securities, LLC

NAV Calculation (,000 except as indicated)	**2017**	**2018E**	**2019E**	**2020E**
PV-10 Value	$ 1,034,151	$ 1,924,518	$ 2,667,970	$ 3,432,651
less long-term debt	$ (718,315)	$ (500,000)	$ (500,000)	$ (500,000)
bank debt	$ -	$ (132,000)	$ (200,000)	$ -
working capital (deficit)	$ 433,040	$ 12,239	$ 239	$ 15,239
other assets	$ -	$ -	$ -	$ -
Net Asset Value	$ 748,876	$ 1,304,757	$ 1,968,209	$ 2,947,890
Shares Outstanding	388,872	390,043	446,054	453,400
NAV per Share	$ 1.93	$ 3.35	$ 4.41	$ 6.50
Kingfisher Midstream EBITDA	$ 42,000	$ 98,761	$ 151,885	$ 174,177
Kingfisher Midstream Multiple	10.0x	10.0x	10.0x	10.0x
Kingfisher Midstream NAV		$ 987,606	$ 1,518,847	$ 1,741,768
Kingfisher Midstream NAV per Share	$ 1.08	$ 2.53	$ 3.41	$ 3.84
Probables (mcfe):	2,233,352	1,579,071	806,483	0
Probable value @ 50% of P1 ($/mcfe)	$ 0.49	$ 0.59	$ 0.59	$ 0.59
Probable NAV per share	$ 2.81	$ 2.38	$ 1.06	$ -
NAV per Share (w/ probables)	**$ 4.74**	**$ 5.73**	**$ 5.48**	$\boxed{\$ \ 10.34}$
Pre-tax PV-10 / mcfe	**$ 0.98**	**$ 1.18**	**$ 1.18**	**$ 1.18**
Future Cash ($/mcfe)	$ 5.33	$ 5.73	$ 5.73	$ 5.73
Future Op Costs ($/mcfe)	$ (2.38)	$ (2.38)	$ (2.38)	$ (2.38)
Future Dev Costs ($/mcfe)	$ (1.31)	$ (1.31)	$ (1.31)	$ (1.31)
[illegible]				
Gas price	*$ 2.98*	*$ 2.75*	*$ 2.75*	*$ 2.75*
NGL prices	*$ 15.40*	*$ 24.00*	*$ 24.00*	*$ 24.00*
Oil price	*$ 51.34*	*$ 60.00*	*$ 60.00*	*$ 60.00*
Weighted $/mcfe	*$ 5.17*	*$ 5.96*	*$ 5.96*	*$ 5.96*
[illegible]				
Gas	*$ (0.26)*	*$ (0.26)*	*$ (0.26)*	*$ (0.26)*
NGL	*51%*	*40%*	*40%*	*40%*
Oil	*$ (1.58)*	*$ (2.00)*	*$ (2.00)*	*$ (2.00)*
Realized Price				
Gas	$ 2.72	$ 2.49	$ 2.49	$ 2.49
NGL	$ 26.06	$ 24.00	$ 24.00	$ 24.00
Oil	$ 49.76	$ 58.00	$ 58.00	$ 58.00
Weighted $/mcfe	$ 5.33	$ 5.73	$ 5.73	$ 5.73

Source: Company Reports, Guggenheim Securities, LLC estimates

Alta Mesa Resources Inc. (AMR)
NAV Forecast
Guggenheim Securities, LLC

PV-10 Calculation	2017	2018E	2019E	2020E
Future Cash Flows	$ 5,629,223	$ 9,360,352	$ 12,976,307	$ 16,695,515
Future Operating Costs	$ (2,518,537)	$ (3,890,359)	$ (5,393,227)	$ (6,939,008)
Future Development Costs	$ (976,149)	$ (1,498,933)	$ (2,077,979)	$ (2,673,559)
Future Cash Flows (pre-tax)	**$ 2,134,537**	**$ 3,971,059**	**$ 5,505,102**	**$ 7,082,948**
PV-10 (pre-tax)	$ 1,034,151	$ 1,924,518	$ 2,667,970	$ 3,432,651
Economic Reserve Life (years)	7.6	7.6	7.6	7.6
Reserve/Production Ratio (years)	23.5	21.3	16.1	13.9

Domestic Reserves (mmcfe)	2017	2018E	2019E	2020E
Beginning Reserves	777,499	1,057,087	1,634,605	2,266,062
Revisions - performance	33,408	0	0	0
- 5 year rule	0	0	0	0
- other	0	0	0	0
Extensions, Discoveries	279,642	654,280	772,588	858,583
Purchases	11,616	0	0	0
Sales	0	0	0	0
Production	(45,078)	(76,763)	(141,131)	(209,095)
Ending Reserves	1,057,087	1,634,605	2,266,062	2,915,550
% Reserve Growth	*36%*	*36%*	*30%*	*25%*
PDP	313,254	490,381	679,819	874,665
% Gas	*39%*	*39%*	*39%*	*39%*
% NGLs	*21%*	*21%*	*21%*	*21%*
% Oil	*41%*	*41%*	*41%*	*41%*
% PUD	*70%*	*70%*	*70%*	*70%*

Source: Company Reports, Guggenheim Securities, LLC estimates

PX 321

Category: Chats/Private/[redacted]
From: Hal Chappelle
To: Mike McCabe
Timestamp: 3/19/2018 7:47:04 PM -04:00
Type: iMessage

Have you gotten any more insight into KFM fourth-quarter results?

Category: Chats/Private/[redacted]
From: Mike McCabe
To: Hal Chappelle
Timestamp: 3/19/2018 7:52:23 PM -04:00
Type: iMessage

Yes. Most was a one time fuel adjustment charge they missed all year

Category: Chats/Private/[redacted]
From: Hal Chappelle
To: Mike McCabe
Timestamp: 3/19/2018 7:53:38 PM -04:00
Type: iMessage

Well, we own it. You have some interesting explanations to develop

Category: Chats/Private[redacted]
From: Mike McCabe
To: Hal Chappelle
Timestamp: 3/19/2018 7:55:54 PM -04:00
Type: iMessage

As in why didn't their auditor catch for our filing since they found out in August and audited Q3

Category: Chats/Private/[redacted]
From: Mike McCabe
To: Hal Chappelle
Timestamp: 3/19/2018 8:06:03 PM -04:00
Type: iMessage

I am more worried about a class action law suit being filed since Proxy numbers were wrong and we have to restate or something akin to that

PX 322

From: Sims Bruns [sbruns@AltaMesa.net]
on behalf of Sims Bruns <sbruns@AltaMesa.net> [sbruns@AltaMesa.net]
Sent: 3/21/2018 3:35:02 PM
To: Tim Turner [tturner@AltaMesa.net]
Subject: RE: Production Data
Attachments: Analyst Production Guidance (SAB).pptx

Here's where I'm at so far. Not looking good. Unless I'm misunderstanding the data in the workbook (which is totally possible!), what's out there, even massaged appropriately, doesn't appear to live up to our type curves.
Minimal text in the PowerPoint at this time. Figured we would just talk through the pictures and wordsmith (or re-work) from there.

See you in the morning, boss.

SAB

From: Tim Turner
Sent: Wednesday, March 21, 2018 3:30 PM
To: Sims Bruns <sbruns@AltaMesa.net>
Subject: Production Data

Sims,

How's the production data analysis going? Thought we might have an interim look in the morning if that works for you. Thanks,

Tim